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
IRO-018-1 AND TOP-010-1

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standards IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities and TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities. NERC requests that the Commission approve the proposed Reliability Standards (**Exhibit A**) and find that they are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4] NERC also requests approval of the associated implementation plan (**Exhibit B**) and the associated Violation Risk Factors and Violation Severity Levels for the proposed standards (**Exhibit D**).

As required by Section 39.5(a)[5] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed Reliability Standards, a demonstration that the

1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2014).

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, capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary of Terms"), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

5 18 C.F.R. § 39.5(a) (2012).

proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[6] (**Exhibit C**), and a summary of the standard development history (**Exhibit H**). The proposed Reliability Standards were adopted by the NERC Board of Trustees on May 5, 2016.

This Petition is organized as follows: Section I of the Petition presents an executive summary of the proposed Reliability Standards. Section II of the Petition provides the individuals to whom notices and communications related to the filing should be provided. Section III provides background on the regulatory structure governing the Reliability Standards approval process. This section also provides information on the development of the proposed Reliability Standards through Project 2009-02, Real-time Reliability Monitoring and Analysis Capabilities and the Commission directives and report recommendations considered as part of the scope for this project. Section IV of the Petition provides a detailed discussion of the proposed Reliability Standards and explains how the proposed standards address report recommendations and satisfy certain outstanding Commission directives related to Real-time monitoring and analysis capabilities.

I. EXECUTIVE SUMMARY

Inadequate situational awareness has been cited as one of the causes of the August 2003 blackout affecting the northeastern United States and Canada and the 2011 blackout affecting the southwestern United States and Baja, Mexico. Reports prepared following these events have provided recommendations for new and revised Reliability Standards to enhance Real-time situational awareness and address the other primary and contributing causes of these events.

[6] The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See 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 P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

Over the last several years, NERC has addressed many of the recommendations from these reports. As a result, Reliability Standards affecting the operating reliability of the Bulk Electric System have improved significantly since first becoming mandatory in 2007. Among other things, the revised Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards approved by the Commission in Order No. 817[7] (referred to herein as the "revised TOP and IRO Reliability Standards") provide rigorous functional requirements for Real-time monitoring and analysis.

In reviewing these reports and the Commission's outstanding directives from Order No. 693,[8] NERC identified further opportunity to enhance reliability and complement the existing functional requirements for Real-time monitoring and analysis. Specifically, NERC developed proposed Reliability Standards IRO-018-1 and TOP-010-1 to improve Real-time situational awareness capabilities and enhance reliable operations by requiring Reliability Coordinators, Transmission Operators, and Balancing Authorities to provide operators with awareness of monitoring and analysis capabilities, including alarm availability, so that operators may take appropriate steps to protect reliability. The proposed standards accomplish this as follows. First, the proposed standards require applicable entities to provide notification to operators of Real-time monitoring alarm failures. Second, the proposed standards require applicable entities to implement Operating Processes or Operating Procedures to: (i) provide operators with indication(s) of the quality of information being provided by their monitoring and analysis

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[7] Order No. 817, *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, 153 FERC ¶ 61,178 (2015) ("Order No. 817"). In Order No. 817, the Commission approved Reliability Standards TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1. However, the Commission directed that NERC make certain modifications to the standards within 18 months of the effective date of the Final Rule. *See* Order No. 817 at P 35, 47, and 51. These directives are currently being considered through Project 2016-01 Modifications to TOP and IRO Standards.

[8] Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*, FERC Stats. & Regs. ¶ 31,242 ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

capabilities; and (ii) address deficiencies in the quality of information being provided by their monitoring and analysis capabilities.

The proposed Reliability Standards address certain Commission directives from Order No. 693 related to requiring a minimum set of capabilities be made available to operators.[9] Further, the proposed Reliability Standards address certain recommendations from the 2008 report of the NERC Operating Committee Real-time Tools Best Practices Task Force ("RTBP Task Force") relating to the availability of key Real-time monitoring and analysis capabilities.[10] The proposed Reliability Standards also address a recommendation from the joint FERC and NERC report on the 2011 Arizona-Southern California outage that entities take steps to ensure the adequacy and operation of their Real-time tools.[11] As such, the proposed Reliability Standards represent an important addition to the body of Reliability Standards for the reliability of the Bulk Power System.

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[9] *See* Order No. 693 at PP 905, 1660, and 1875 and *infra* Section III.C.

[10] *See* RTBP Task Force, *Real-Time Tools Survey Analysis and Recommendations* (Mar. 2008) ("2008 RTBP Task Force Report"), included as Exhibit G-2 to this Petition. The report is available on NERCs website at: http://www.nerc.com/comm/OC/Realtime%20Tools%20Best%20Practices%20Task%20Force%20RTBPTF%2020/Real-Time%20Tools%20Survey%20Analysis%20and%20Recommendations.pdf.

As explained in further detail below, the RTBP Task Force was initiated in response to Recommendation 22 of the final report on the August 2003 blackout. *See* U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (Apr. 2004) ("August 2003 Blackout Report"), *available at* http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf. For convenience, the August 2003 Blackout Report is also included as Exhibit G-1 to this Petition.

[11] *See* FERC and NERC, *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (Apr. 2012) ("2011 Southwest Outage Report"), included as Exhibit G-3 to this Petition. The report is also available on NERC's website at: http://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[12]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[13] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[14] 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. Section 215(d)(5)[15] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[16] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and

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[12] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2016), to allow the inclusion of more than two persons on the service list in this proceeding.

[13] 16 U.S.C. § 824o (2012).

[14] *Id.* § 824o(b)(1).

[15] *Id.* § 824o(d)(5).

[16] 18 C.F.R. § 39.5(a) (2016).

enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk Power System and to ensure that Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[17] and Section 39.5(c)[18] 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.

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.[19] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[20]

In its order certifying NERC as the Commission's ERO, 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,[21] and thus satisfy certain of the criteria for approving Reliability Standards.[22] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk Power System.

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17 16 U.S.C. § 824o(d)(2).

18 18 C.F.R. § 39.5(c)(1).

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

20 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.

21 *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 at P 250 (2006).

22 Order No. 672 at PP 268, 270.

NERC considers the comments of all stakeholders. Stakeholders must approve, and the NERC Board of Trustees must adopt, a Reliability Standard before NERC submits the Reliability Standard to the Commission for approval.

C. Commission Directives Relating to Real-time Monitoring and Analysis Capabilities

In Order No. 693, the Commission approved 83 Reliability Standards, including the original TOP and IRO Reliability Standards. While approving those standards, the Commission directed NERC to develop modifications to ensure that operating entities would have adequate tools to perform their Real-time reliability functions.

First, the Commission directed NERC to develop modifications to Reliability Standard IRO-002-1 – Reliability Coordination – Facilities[23] as follows:

> [T]he Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe that this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. Further…such a requirement promotes a more proactive approach to maintaining reliability.[24]

As "a particular product could become obsolete and technology improves over time," the Commission clarified that its intent behind this directive was "to have the ERO develop a requirement that identifies capabilities, not actual tools or products."[25]

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23 Order No. 693 at P 905. The Commission approved the currently-effective version of the standard, IRO-002-2, in Docket No. RM10-15-000. *See* Order No. 748, *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, 134 FERC ¶ 61,213, *order on clarification*, Order No. 748-A, 136 FERC ¶ 61,030 (2011) ("Order No. 748"). In Order No. 817, the Commission approved Reliability Standard IRO-002-4 – Reliability Coordination – Monitoring and Analysis, to become effective April 1, 2017.

24 Order No. 693 at P 905.

25 Order No. 693 at P 906.

Second, the Commission directed NERC to develop modifications to TOP-006-1 – Monitoring System Conditions.[26] Again, the Commission stated that its intent was for NERC to identify minimum capabilities, not specific sets of tools:

> We adopt our proposal to require the ERO to develop a modification related to the provision of a minimum set of analytical tools . . . we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.[27]

In addition to the revisions to TOP and IRO standards, the Commission directed NERC to develop a modification to Reliability Standard VAR-001-1 – Voltage and Reactive Control related to Real-time tools.[28] Specifically, the Commission directed NERC to modify the standard to require periodic performance of voltage stability analysis "using online techniques where commercially available, and offline simulation tools where online tools are not available, to assist Real-time operations."[29]

D. Report Recommendations Relating to Real-time Monitoring and Analysis Capabilities

The Commission's Order No. 693 directives highlighted the need for a minimum set of capabilities to be available to assist operators in making Real-time decisions, a concern that has been echoed in reports prepared following the August 2003 blackout and the 2011 Southwest outage events. Reliability Standards relating to the operating reliability of the Bulk Power

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[26] Order No. 693 at P 1660. The Commission approved the currently-effective version of the standard, TOP-006-2, in Order No. 748. In Order No. 817, the Commission approved three TOP Reliability Standards to replace the existing suite of TOP standards, including Reliability Standard TOP-006-2, effective April 1, 2017.

[27] Order No. 693 at P 1660.

[28] Order No. 693 at P 1875. VAR-001 was most recently revised as part of Project 2013-04 – Voltage and Reactive Control and was approved by the Commission in Docket No. RD14-11-000. *See N. Am. Elec. Reliability Corp.* (Aug. 1, 2014) (unpublished letter order) and *N. Am. Elec. Reliability Corp.*, Docket No. RD15-6-000 (Nov. 13, 2015) (unpublished letter order) (approving errata version VAR-001-4.1).

[29] *See* Order No. 693 at ¶ 1875.

System have improved significantly since 2007, and many of the issues and recommendations highlighted in these reports have since been addressed. However, these reports provide additional considerations for improving Real-time monitoring and analysis capabilities, as discussed below.

1. <u>The August 2003 Blackout Report and the 2008 RTBP Task Force Report</u>

The largest blackout in history to affect North America began on the afternoon of August 14, 2003 and disrupted over 61,800 megawatts of electric load in the northeastern United States and the Canadian province of Ontario. The August 2003 Blackout Report identified inadequate situational awareness as one of the key causes of the blackout, among a number of principal and contributing causes.[30] The August 2003 blackout was linked to dysfunction of Supervisory Control and Data Acquisition and energy management systems.[31] Additionally, investigators pointed out that several deficiencies leading to the August 2003 blackout were identified as weaknesses in previous outages, indicating the need for more effective response.[32] A recurring recommendation focused on providing capabilities for operators to evaluate courses of action. These observations led to Recommendation 22 of the August 2003 Blackout Report for NERC to "evaluate and adopt better real-time tools for operators and reliability coordinators."[33]

In response to this recommendation, NERC formed the RTBP Task Force in 2004. The RTBP Task Force was charged with identifying the best practices for Real-time reliability tools used to build and maintain Real-time network models, perform state estimation and contingency analysis, and maintain situational awareness in accordance with NERC Reliability Standards. The RTBP Task Force was also instructed to develop guidelines for minimally acceptable

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30 *See* August 2003 Blackout Report at 18.

31 *See, e.g., id.* at 52.

32 *See id.* at 159.

33 *Id.*

capabilities for these reliability tools and to recommend specific requirements to be included in Reliability Standards for these tools. In 2008, following extensive information gathering and analysis, the RTBP Task Force issued a report which included recommendations for new and enhanced Reliability Standards, operating guidelines, and areas for further analysis.

In the years since the issuance of this report, many of its recommendations have been addressed by other Reliability Standards, including the revised TOP and IRO Reliability Standards. However, certain recommendations relating to Real-time monitoring and analysis capabilities were not fully addressed or remained to be considered.

Among these recommendations was the recommendation that NERC develop new or revised Reliability Standards to mandate certain tools as mandatory monitoring and analysis tools.[34] The RTBP Task Force also recommended developing new or revised Reliability Standards to address availability of various monitoring and analysis capability processes,[35] as well as to "monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation."[36]

Collectively, these recommendations center on developing Reliability Standards that would enhance situational awareness by providing operator awareness of key monitoring and analysis capabilities, including when alarms are not available or performing their intended function.

2. The 2011 Southwest Outage Report

The need for improved Real-time monitoring and analysis capabilities was again highlighted in the 2011 Southwest Outage Report. On the afternoon of September 8, 2011, the

[34] Specifically, alarm tools, telemetry data systems, network topology processor, state estimator, and contingency analysis. *See* 2008 RTBP Task Force Report at Summary of Recommendations (Recommendation S1).

[35] *See, e.g., id.* Recommendation S7 ("Specify and measure minimum availability for alarm tools.").

[36] *See id.* Recommendation S40.

loss of a single 500 kV line led to widespread cascading outages affecting 2.7 million customers in Arizona, Southern California, and Baja, Mexico. Like the August 2003 blackout, this event was partly due to, or exacerbated by, inadequate Real-time situational awareness. Inadequate operations planning was a significant factor in the failure to maintain a secure N-1 state.[37] However, the 2011 Southwest Outage Report also highlighted several concerns with entities and their ability to monitor, identify, and plan for the next critical contingency in Real-time.[38]

Recommendation 12 of this report states that entities "should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems."[39] While the 2011 Southwest Outage Report's recommendations relating to operations planning, Real-time situational awareness, and frequency of Real-time monitoring and analysis have been primarily addressed by the revised TOP and IRO Reliability Standards,[40] the parts of Recommendation 12 relating to adequacy and operation of Real-time tools are not explicitly covered by Reliability Standard requirements and therefore present areas for improvement.

E. Project 2009-02, Real-time Reliability Monitoring and Analysis Capabilities

Project 2009-02 was formed to address issues relating to Real-time reliability monitoring and analysis capabilities, as highlighted in the Commission's Order No. 693 directives and the report recommendations discussed in the preceding section. Project 2009-02 was first initiated in

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37 2011 Southwest Outage Report at 5.

38 *Id.*

39 *Id.* at 89.

40 See *Petition of the North American Electric Reliability Corporation for Approval of Proposed Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards*, Docket No. RM15-16-000 (Mar. 18, 2015) at Ex. F (Mapping Document of Proposed Reliability Standards to Southwest Outage Report Recommendations).

2009 in response to the work of the RTBP Task Force and used the 2008 RTBP Task Force Report as the basis for the initial work. A Standard Authorization Request ("SAR") drafting team worked to develop a SAR and a concept white paper to establish requirements for the "functionality, performance, and maintenance of Real-time Monitoring and Analysis Capabilities."[41] In early 2011, formal development on Project 2009-02 was paused to prioritize efforts on other projects, including other projects to revise the TOP and IRO Reliability Standards.

NERC resumed work on Project 2009-02 in early 2015. As many Reliability Standards and definitions had been developed or revised in the intervening years, including the revised TOP and IRO Reliability Standards, it was necessary to develop a new project scope to determine which issues had been addressed through other projects and which issues remained to be addressed through Project 2009-02.

To develop the new project scope, the Project 2009-02 drafting team reviewed the prior work on the project, the Commission's directives from Order No. 693 relating to Real-time monitoring and analysis capabilities, and the findings and recommendations of the August 2003 Blackout Report and the 2008 RTPB Task Force Report. The drafting team also reviewed the 2011 Southwest Outage Report, which was issued after the initial work on Project 2009-02 was paused in 2011, as well as recently-developed Reliability Standards addressing Real-time situational awareness.[42] In June 2015, the drafting team hosted a technical conference to obtain

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[41] *See* Ex. H (Summary of Development and Complete Record of Development) Item 15, April 2010 Standard Authorization Request.

[42] To assist in its work, the drafting team prepared a comprehensive mapping document to show which report recommendations relating to Real-time monitoring and analysis capabilities had been addressed through other Reliability Standards and which recommendations remained to be considered. *See* Exhibit F (Standard Authorization Request Justification, Project 2009-02) Appendix – Report Recommendations.

industry input on reliability issues to be addressed in this project and to hear industry perspectives on the use of Real-time situational awareness capabilities for reliable operations.

Based on its comprehensive review and outreach, the Project 2009-02 drafting team determined that identified reliability issues persist in the area of Real-time situational awareness capabilities. The Project 2009-02 drafting team determined that reliability could be improved by: (i) promoting a common understanding of monitoring as it applies to Real-time situational awareness; (ii) providing operators with indication(s) of the quality of information being provided by monitoring and analysis capabilities; and (iii) providing operators with notification(s) during unplanned loss of monitoring capabilities.

Although certain recommendations from the 2008 RTBP Task Force Report recommended developing Reliability Standards to require a minimum set of tools, the Project 2009-02 drafting team concluded that prescriptive requirements for Real-time tools should not be within the scope of Project 2009-02. The revised definition of Real-time Assessment and the requirements in Reliability Standards IRO-008-2 and TOP-001-3, discussed below, provide applicable entities with the flexibility to determine which Real-time tools, such as state estimator, contingency analysis, and stability applications, are necessary to meet their Real-time reliability functions. Therefore, rather than prescribing specific tools, the Project 2009-02 drafting team determined that it would be appropriate to address the recommendations by developing technology-neutral Reliability Standards.

The drafting team began work on proposed Reliability Standards IRO-018-1 and TOP-010-1 in August 2015. Following two comment and ballot periods, the proposed standards were approved by the ballot pool in February 2016. The NERC Board of Trustees adopted the proposed standards on May 5, 2016.

IV. JUSTIFICATION FOR APPROVAL

As discussed in **Exhibit C** and below, proposed Reliability Standards IRO-018-1 and TOP-010-1 satisfy the Commission's criteria in Order No. 672, and are just, reasonable, not unduly discriminatory or preferential, and in the public interest.

Maintaining adequate situational awareness is essential for the reliable operation of the Bulk Power System. As described in the 2008 RTBP Task Force Report, situational awareness means "ensuring that accurate information on current system conditions, including the likely effects of future contingencies, is continuously available in a form that allows operators to quickly grasp and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations."[43] Situational awareness may be thought of as encompassing two broad capabilities: monitoring and analysis. To be effective in support of situational awareness, Real-time monitoring and analysis must:

- be performed with sufficient frequency to allow operators to understand operating conditions and take corrective actions when necessary;
- provide awareness of information quality to allow operators to assess the accuracy of information being received on system conditions and take corrective actions when necessary; and
- indicate when monitoring or analysis processes are not operating normally or are unavailable in order to provide operator awareness of the accuracy of the information being provided.[44]

The existing, Commission-approved Reliability Standards, including the revised TOP and IRO Reliability Standards and revised definition of Real-time Assessment, provide rigorous requirements for performing Real-time monitoring and analysis to support the reliable operation of the Bulk Power System. However, reliability would be improved by instituting requirements

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43 2008 RTBP Task Force Report at 3.

44 *See* Ex. F (Standard Authorization Request Justification, Project 2009-02) at 10.

to provide operator awareness of monitoring, alarming, and analysis quality and tool availability to perform as intended. Proposed Reliability Standards IRO-018-1 and TOP-010-1 support effective Real-time monitoring and analysis and thereby enhance reliable operations by ensuring that:

- operators are provided with indications of the quality of information being provided by monitoring and analysis capabilities;
- applicable entities have procedures in place to identify and address high-priority data and analysis quality issues; and
- operators receive notifications during unplanned loss of alarming capabilities.

In this section, NERC: (i) describes how the proposed Reliability Standards complement the revised TOP and IRO Reliability Standards and definitions approved by the Commission in Order No. 817 to improve Real-time situational awareness;[45] (ii) discusses the requirements of the proposed standards on a requirement-by-requirement basis; and (iii) explains how the proposed standards address the report recommendations and Commission directives related to Real-time monitoring and awareness capabilities.

A. Overview of Requirements Relating to Real-time Monitoring and Analysis Capabilities

Real-time monitoring, or monitoring the Bulk Electric System in Real-time, is a primary function of Reliability Coordinators, Transmission Operators, and Balancing Authorities as required by TOP and IRO Reliability Standards. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include the following activities performed in Real-time:

[45] Requirements for Real-time monitoring and analysis are also contained in currently-effective Reliability Standards which are pending retirement under the Project 2014-03 implementation plan. Please refer to Exhibit E (Consideration of Directives) for the currently-effective requirements.

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirements for the Reliability Coordinator, Transmission Operator, and Balancing Authority to perform Real-time monitoring are specified in Commission-approved Reliability Standards IRO-002-4[46] (Reliability Coordinator); TOP-001-3[47] (Transmission Operator); and TOP-001-3[48] and the BAL standards (Balancing Authority).

The analysis component of Real-time situational awareness is described by the revised definition of Real-time Assessment:

<u>Real-time Assessment</u>

> 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

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46 *See* IRO-002-4 Requirement 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.

47 *See* TOP-001-3 Requirement R10:

> 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.

48 *See* TOP-001-3 Requirement R11:

> 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.

> 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.)

Requirements for the Reliability Coordinator to perform Real-time Assessments are specified in IRO-008-2,[49] and requirements for the Transmission Operator to perform Real-time Assessments are specified in TOP-001-3.[50]

The Reliability Coordinator uses a set of Real-time data identified in IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments, whereas the Transmission Operator uses a set of Real-time data identified in TOP-003-3 Requirement R1. The Balancing Authority uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring.

Proposed Reliability Standards IRO-018-1 and TOP-010-1 do not create new obligations to perform Real-time monitoring or analysis. Rather, the proposed standards build upon existing requirements to support effective Real-time monitoring and analysis and improved situational awareness and thereby enhance reliable operations. Proposed Reliability Standard IRO-018-1 is applicable to Reliability Coordinators. Proposed Reliability Standard TOP-010-1 contains Requirements which are applicable to Transmission Operators and Balancing Authorities.

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[49] *See* IRO-008-2 Requirement R4:

> Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

[50] *See* revised definition of Real-time Assessment and TOP-001-3 Requirement R13:

> Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

B. Proposed Reliability Standard Requirements

1. Requirements to Address Real-time Data Quality Issues: IRO-018-1 R1, TOP-010-1 R1, and TOP-010-1 R2

As noted in the preceding section, existing Reliability Standards contain requirements to perform monitoring and Real-time Assessments. Proposed Reliability Standards IRO-018-1 Requirement R1, TOP-010-1 Requirement R1, and TOP-010-1 Requirement R2 build upon these requirements to support effective situational awareness by requiring each Reliability Coordinator, Transmission Operator, and Balancing Authority to implement an Operating Process[51] or Operating Procedure[52] to address the quality of the Real-time data necessary to perform its Real-time data monitoring and Real-time Assessments or analysis functions. Entities continue to address lower-priority data quality issues (i.e. data quality issues not affecting Real-time monitoring or analysis) according to their operating practices.

These requirements, along with the proposed requirements discussed in the subsequent sections, address recommendations from the 2008 RTBP Task Force Report by specifying monitoring and analysis capabilities for situational awareness. Further, the proposed requirements address the 2011 Southwest Outage Report's recommendation that entities should take measures to ensure the adequacy and operation of their Real-time tools.

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[51] Operating Process is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("Glossary") as:

> A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

[52] Operating Procedure is defined in the Glossary as:

> A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

The specific requirements are as follows.

IRO-018-1 Requirement R1, applicable to Reliability Coordinators, provides:

> <u>**IRO-018-1**</u>
>
> **R1**. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]
>
> **1.1**. Criteria for evaluating the quality of Real-time data;
> **1.2**. Provisions to indicate the quality of Real-time data to the System Operator; and
> **1.3**. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

Proposed Reliability Standard TOP-010-1 Requirement R1 contains identical requirements applicable to Transmission Operators.

Similarly, proposed Reliability Standard TOP-010-1 Requirement R2 requires each Balancing Authority to implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its required analysis functions and Real-time monitoring as follows:

> <u>**TOP-010-1**</u>
>
> **R2.** Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]
>
> **2.1**. Criteria for evaluating the quality of Real-time data;
> **2.2**. Provisions to indicate the quality of Real-time data to the System Operator; and
> **2.3**. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.

The Operating Process or Operating Procedure required by proposed IRO-018-1 Requirement R1 and proposed TOP-010-1 Requirements R1 and R2 consists of three parts. First, the Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data. As described in the Guidelines and Technical Basis section of the proposed standards, the criteria support identification of data quality issues, which may include: (i) data outside of a prescribed data range; (ii) analog data not updated within a predetermined time period; (iii) data entered manually to override telemetered information; or (iv) data otherwise identified as invalid or suspect.

Second, the Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. To satisfy this requirement, the applicable entity could use descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications.

Third, the required Operating Process or Operating Procedure must include actions to address Real-time data quality issues affecting the Reliability Coordinator or Transmission Operator's Real-time Assessments, or in the case of the Balancing Authority, Real-time data quality issues affecting its analysis functions.

In drafting these requirements, the Project 2009-02 drafting team recognized that the applicable entity may have limited ability to resolve (or correct) bad or suspect data coming from a third party. Therefore, the proposed requirements provide applicable entities with the flexibility to determine which steps are appropriate to maintain adequate situational awareness. The actions an entity may take to address Real-time data quality issues could be the same as the process used to resolve data conflicts required by IRO-010-2 Requirement R3 Part 3.2 or TOP-003-3 Requirement R5 Part 5.2, provided that this process addresses Real-time data quality issues.

Other examples of actions to address data quality issues include, but are not limited to: (i) notifying the entities that are providing the Real-time data; (ii) taking corrective actions on the applicable entity's own data; (iii) changing data sources or other inputs so the data quality issue no longer affects Real-time Assessments; or (iv) entering data manually and updating as necessary.

2. Requirements to Address the Quality of Analysis used in Real-time Assessments: IRO-018-1 R2 and TOP-010-1 R3

Proposed Reliability Standards IRO-018-1 Requirement R2 and TOP-010-1 Requirement R3 ensure that Reliability Coordinators and Transmission Operators implement Operating Processes or Operating Procedures to address issues related to the quality of the analysis used in Real-time Assessments. As discussed above, requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the type of analysis used in Real-time Assessments may include state estimation, Real-time contingency analysis, stability analysis, or other studies used for Real-time Assessments.

Proposed IRO-018-1 Requirement R2, applicable to Reliability Coordinators, provides as follows:

> **R2.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]
>
> **2.1**. Criteria for evaluating the quality of analysis used in its Real-time Assessments;
> **2.2.** Provisions to indicate the quality of analysis used in its Real-time Assessments; and
> **2.3.** Actions to address analysis quality issues affecting its Real-time Assessments.

Proposed Reliability Standard TOP-010-1 Requirement R3 contains identical requirements applicable to Transmission Operators.

These requirements have the same general structure as the proposed requirements for data quality issues. First, the Reliability Coordinator or Transmission Operator's Operating Process or Operating Procedure must include criteria for evaluating the quality of analysis. Examples of the types of criteria that may be used to evaluate the quality of analysis include, but are not limited to, solution tolerances, correlation with Real-time data, or the number of contingencies analyzed from the set of potential contingencies.

Second, the Operating Process or Operating Procedure must describe how the quality of analysis results used in Real-time Assessments will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

Third, the Operating Process or Operating Procedure must include actions to address those analysis quality issues affecting its Real-time Assessments. Similar to the requirements for data quality issues, Reliability Coordinators and Transmission Operators have flexibility to determine the appropriate actions to take in situations where analysis quality issues are affecting their ability to perform Real-time Assessments.

3. Requirements for Alarm Processor Failure Monitoring: IRO-018-1 R3, TOP-010-1 R4

In the 2008 RTBP Task Force Report, the RTBP Task Force recommended developing a requirement to specify minimum availability of alarm tools (Recommendation S7). Proposed Reliability Standards IRO-018-1 Requirement R3 and TOP-010-1 Requirement R4 address the situational awareness objectives associated with this recommendation by providing for operator awareness when key alarming tools are not performing as intended.

Proposed Reliability Standard IRO-018-1 Requirement R3, applicable to Reliability Coordinators, states:

> **R3.** Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a

> failure of its Real-time monitoring alarm processor has occurred. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

Proposed TOP-010-1 Requirement R4 contains an identical requirement applicable to Transmission Operators and Balancing Authorities.

As specified in the Guidelines and Technical Basis section of the proposed Reliability Standards, the alarm process monitor should be designed and implemented such that a stall of the Real-time monitoring alarm processor does not cause a failure of the alarm process monitor. The proposed requirements provide applicable entities with flexibility to determine whether to use an alarm process monitor that is a separate system or an application within a Real-time monitoring system.

C. Consideration of FERC Directives

As discussed in Section III.C above, the Commission directed NERC in Order No. 693 to modify TOP and IRO Reliability Standards to require a minimum set of capabilities be made available to operators.[53] Although the Commission contemplated modifications to specific Reliability Standards, NERC submits that proposed Reliability Standards IRO-018-1 and TOP-010-1, together with other currently-effective and Commission-approved Reliability Standards, address the reliability concerns underlying the Commission's directives in an equally effective and efficient manner, as set forth below.

1. Order No. 693 P 905 Directive

In Order No. 693, the Commission directed NERC to modify IRO-002-1 to develop a requirement that identifies the minimum capabilities that must be made available to the Reliability Coordinator to ensure "that a reliability coordinator has the tools it needs to perform

[53] Order No. 693 at P 905-906 (directing NERC to modify IRO-002-1) and P 1660 (directing NERC to modify TOP-006-1).

its functions."[54] The monitoring and analysis capabilities required by proposed Reliability Standard IRO-018-1 and other IRO Reliability Standards ensure Reliability Coordinators have the capabilities to maintain Real-time situational awareness.

Monitoring capabilities. Requirements for the Reliability Coordinator to perform Real-time monitoring are specified in Commission-approved Reliability Standard IRO-002-4.[55] As discussed in the preceding section, proposed Reliability Standard IRO-018-1 Requirement R1 addresses the quality of the Real-time data needed by the Reliability Coordinator to perform its monitoring and Real-time Assessments by requiring each Reliability Coordinator to implement a documented procedure to address data quality issues. Proposed IRO-018-1 Requirement R3 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring Reliability Coordinators to have an alarm process monitor.

Analysis Capabilities. Requirements for the Reliability Coordinator to perform Real-time Assessments are specified in Commission-approved Reliability Standard IRO-008-2 and the approved revised definition of Real-time Assessment. Under proposed Reliability Standard IRO-018-1 Requirement R2, each Reliability Coordinator is required to implement a documented procedure to address the quality of the analysis used in its Real-time Assessments.

2. Order No. 693 P 1660 Directive

In Order No. 693, the Commission directed NERC to develop a modification to Reliability Standard TOP-006-1 related to the provision of a minimum set of analytical tools (i.e. capabilities) "that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System."[56] As discussed below, the monitoring and

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[54] Order No. 693 at P 905.

[55] As noted above, please refer to Exhibit E (Consideration of Directives) for the currently-effective requirements for Real-time monitoring and analysis.

[56] Order No. 693 at P 1660.

analysis capabilities required by proposed TOP-010-1 and other Commission-approved TOP Reliability Standards ensure that Transmission Operators and Balancing Authorities have the capabilities to maintain Real-time situational awareness and thus address the Commission's directive in an equally effective and efficient manner.

Monitoring Capabilities. Requirements for Transmission Operators and Balancing Authorities to perform Real-time monitoring are specified in Commission-approved Reliability Standard TOP-001-3 and the BAL Reliability Standards. As discussed in the preceding section, proposed Reliability Standard TOP-010-1 Requirements R1 and R2 address the quality of the Real-time data needed by Transmission Operators and Balancing Authorities to perform their Real-time monitoring and Real-time Assessments or analysis functions by requiring these entities to implement a documented procedure for addressing data quality issues. Proposed Reliability Standard TOP-010-1 Requirement R4 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring Transmission Operators and Balancing Authorities to have an alarm process monitor.

Analysis Capabilities. Requirements for the Transmission Operator to perform Real-time Assessments are specified in Commission-approved Reliability Standard TOP-001-3. Under proposed Reliability Standard TOP-010-1 Requirement R3, each Transmission Operator is required to implement a documented procedure to address the quality of the analysis used in its Real-time Assessments.

3. Order No. 693 P 1875 Directive

In addition to the two directives discussed above, the Commission also directed NERC to modify Reliability Standard VAR-001-1 to "to include Requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations."[57]

This directive was considered in establishing the scope of Project 2009-02. However, NERC maintains that this directive has now been addressed by other TOP, IRO, and VAR standards approved by the Commission. Accordingly, Project 2009-02 did not develop additional requirements to address this directive. NERC respectfully requests that the Commission find that the concerns underlying this directive have been addressed in an equally effective and efficient manner through the framework provided by these other standards.

Reliability Standard VAR-001 was most recently revised in Project 2013-04 Voltage & Reactive Control.[58] Reliability Standard VAR-001-4.1 Requirement R1 provides that the Transmission Operator shall specify a system voltage schedule as part of its plan to operate within System Operating Limits ("SOLs") and Interconnection Reliability Operating Limits ("IROLs"). Reliability Standard VAR-001-4.1 does not include an explicit requirement for periodic performance of voltage stability analysis because "such analysis would be performed pursuant to the SOL methodology developed under FAC standards."[59]

Reliability Coordinators and Transmission Operators are required to periodically perform Real-time Assessments consisting of an evaluation of system conditions "to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions."[60] Requirements for performing Real-time Assessments are contained in currently-effective Reliability Standard IRO-

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57 Order No. 693 at P 1875.

58 Reliability Standard VAR-001-4 was approved by the Commission in Docket No. RD14-11-000. *See N. Am. Elec. Reliability Corp.* (Aug. 1, 2014) (unpublished letter order). The Commission approved the currently-effective errata version VAR-001-4.1 in Docket No. RD15-6-000. *See N. Am. Elec. Reliability Corp.* (Nov. 13, 2015) (unpublished letter order).

59 Reliability Standard VAR-001-4.1, Guidelines and Technical Basis.

60 *See* revised definition of Real-time Assessment.

008-1 and Commission-approved Reliability Standards IRO-008-2 and TOP-001-3 as discussed above. Real-time Assessments assist operators in maintaining operations within established SOLs and IROLs, to include voltage stability criteria. Under these requirements, applicable entities must use whatever analysis is necessary to obtain an evaluation of system conditions, which may include Real-time voltage stability analysis. These requirements do not prescribe the use of specific techniques or tools.

In light of the comprehensive and flexible framework that is now in place, NERC submits that the Commission's underlying concern from Order No. 693 has been addressed, and that it is no longer necessary to modify the VAR-001 Reliability Standard to specifically require the performance of voltage stability analysis using online techniques when available or offline simulation tools when not available.

D. Enforceability of the Proposed Reliability Standards

The proposed Reliability Standards contain Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"). The VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standards. The VRFs are one of several elements used to determine an appropriate sanction when the associated Requirement is violated. The VRFs assess the impact to reliability of violating a specific Requirement. The VRFs and VSLs comport with NERC and Commission guidelines related to their assignment. A description of how the proposed VRF and VSL assignments meet these guidelines is provided in **Exhibit D.** Below, NERC provides additional detail to explain how the proposed VRF assignments meet these guidelines.

Each of the Requirements in proposed Reliability Standards IRO-018-1 and TOP-010-1 were assigned a "Medium" VRF. Under NERC's criteria for VRFs, a Medium Risk Requirement 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.

The Commission has set forth several guidelines for evaluating proposed VRFs.[61] First, for Reliability Standard Requirements addressing areas identified in the August 2003 Blackout Report as causes of previous blackouts, the Commission looks to determine whether the assigned VRFs "appropriately reflect their historical critical impact on the reliability of the Bulk Power System." Second, the Commission looks to whether the assigned VRFs are consistent within the Reliability Standard. Third, the Commission evaluates whether the assigned VRFs are consistent among other Reliability Standards with similar Requirements. Fourth, the Commission evaluates whether the proposed VRF assignments are consistent with NERC's definition of the VRF level. Lastly, where a single Requirement co-mingles higher and lower risk reliability objectives, the Commission evaluates whether the VRF has been "watered down" to reflect the lower risk level.

Under these guidelines, NERC's proposed assignment of "Medium" VRFs for the proposed Reliability Standard Requirements is appropriate. First, the proposed Requirements are

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61 *See N. Am. Electric Reliability Corp.*, *Order on Violation Risk Factors*, 119 FERC ¶ 61,145 (2007).

not directly connected to the conclusions or critical areas identified in the August 2003 Blackout Report, but rather address specific recommendations from a NERC technical committee. With respect to the final guideline, the proposed VRF assignments do not reflect the lower of multiple reliability objectives as each requirement contains one reliability objective. With respect to the second, third, and fourth guidelines, the proposed VRF assignments are consistent within the proposed Reliability Standards, among other Reliability Standards with similar Requirements, and with the NERC definition of the VRF level, as discussed below.

The proposed Medium VRF assignments are consistent with the NERC definition. The purpose of the proposed Reliability Standards is to address recommendations regarding Real-time situational awareness and to require entities to take steps to address data or analysis quality concerns to the extent that it affects their ability to perform Real-time monitoring and analysis. The requirements in IRO-018-1 and TOP-010-1 address issues related to the quality and availability of monitoring and analysis capabilities used by Reliability Coordinators, Transmission Operators, and Balancing Authorities in maintaining reliable operations. Violation of any of these requirements could directly affect the ability to effectively monitor and control the Bulk Electric System. However, violation of any of these requirements is unlikely to lead to Bulk Electric System instability, separation, or cascading failures.

Further, NERC's proposed assignment of Medium VRFs is both consistent within the proposed Reliability Standards, which contain similar responsibilities for different applicable entities, and with other Reliability Standards that involve effective monitoring and control of the Bulk Electric System. For example, Reliability Standards TOP-003-3 Requirement 5 and IRO-010-2 Requirement R3, which provide that applicable entities shall provide the data necessary for Transmission Operators and Reliability Coordinators to perform Real-time monitoring and

Real-time Assessments, have each been assigned a Medium VRF. Reliability Standard TOP-001-3 Requirement R9, which requires Transmission Operators and Balancing Authorities to notify Reliability Coordinators and others of planned and unplanned outages of monitoring and assessment capabilities, has also been assigned a Medium VRF.[62]

In addition to the proposed VRFs and VSLs, the proposed Reliability Standards also include Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. These Measures help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[63]

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the proposed implementation plan attached to this Petition as **Exhibit B**. NERC proposes a single implementation plan, to govern implementation of both proposed Reliability Standards IRO-018-1 and TOP-010-1. Under this plan, the proposed Reliability Standards would become effective the first day of the first calendar quarter that is 18 months following regulatory approval.

The proposed implementation period is designed to allow applicable entities sufficient time to develop and implement the required Operating Processes or Procedures and, if necessary, implement any upgrades to their Real-time monitoring systems.

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[62] In addition, NERC's proposed VRF assignments are appropriate in light of the Commission-approved VRF assignments for related Reliability Standards. The proposed requirements relate to implementing Operational Processes or Operational Procedures to address Real-time data quality and analysis issues. The actual Requirements to perform Real-time Assessments have been assigned a High VRF. *See, e.g.*, TOP-001-3 Requirement 13. Requirements to maintain data specifications for the data needed to perform Real-time monitoring and Real-time Assessments have been assigned a Low VRF. *See, e.g.*, TOP-003-3 Requirement R1.

[63] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

VI. **<u>CONCLUSION</u>**

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

- approve proposed Reliability Standards IRO-018-1, TOP-010-1, and associated elements included in **Exhibit A**; and
- approve the implementation plan included in **Exhibit B.**

Respectfully submitted,

<u>/s/ Lauren A. Perotti</u>

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Exhibit A

Proposed Reliability Standards IRO-018-1 and TOP-010-1

IRO-018-1 Reliability Standard

A. Introduction

1. **Title:** **Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities**

2. **Number:** **IRO-018-1**

3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinators

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator or supporting logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R2. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

2.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

2.3. Actions to address analysis quality issues affecting its Real-time Assessments.

M2. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R2. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R3. Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Reliability Coordinator shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 it was compliant for the full-time period since the last audit.

The Reliability Coordinator 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 Reliability Coordinator shall retain evidence of compliance for Requirements R1 and R3 and Measures M1 and M3 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall retain evidence of compliance for Requirement R2 and Measure M2 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator 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 Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes 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 Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of

		analysis used in its Real-time Assessments did not include one of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include two of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.
R3.	N/A	N/A	The Reliability Coordinator has an alarm process monitor but the alarm process monitor did not provide a notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The Reliability Coordinator does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	October 30, 3015	New standard developed in Project 2009-02 to respond to recommendations in Real-time Best Practices Task Force Report and FERC directives.	N/A
1	May 5, 2016	Adopted by the Board of Trustees.	New

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability Standards. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The RC uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform monitoring and Real-time Assessments appear in other Reliability Standards.

The RC's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed IRO-018-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the RC shall include actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The RC's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the RC to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the RC;

- Following processes established for resolving data conflicts as specified in IRO-010-1a, IRO-010-2, or other applicable Reliability Standards;
- Taking corrective actions on the RC's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the RC's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R2

Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the types of criteria used to evaluate the quality of analysis used in Real-time Assessments may include solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R3

Requirement R3 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that a stall of the Real-time monitoring alarm processor does not cause a failure of the alarm process monitor.

Rationale

Rationale for Requirement R1: The Reliability Coordinator (RC) uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the RC shall include actions to address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by IRO-010-2 Requirement R3 Part 3.2 provided that this process addresses Real-time data quality issues.

The revision in Part 1.3 to address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R2: Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

Rationale for Requirement R3: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

TOP-010-1 Reliability Standard

A. Introduction

1. **Title:** **Real-time Reliability Monitoring and Analysis Capabilities**

2. **Number:** **TOP-010-1**

3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Operators

   4.1.2. Balancing Authorities

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Transmission Operator shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R2. Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. Criteria for evaluating the quality of Real-time data;

2.2. Provisions to indicate the quality of Real-time data to the System Operator; and

2.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.

M2. Each Balancing Authority shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Balancing Authority implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R3. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

3.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

3.3. Actions to address analysis quality issues affecting its Real-time Assessments.

M3. Each Transmission Operator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R3. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R3; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R4. Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Transmission Operator and Balancing Authority shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 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 applicable entity shall retain evidence of compliance for Requirements R1, R2, and R4, and Measures M1, M2, and M4 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall retain evidence of compliance for Requirement R3 and Measure M3 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity 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.

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 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 Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the

		Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include two of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.
R3.	N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 through Part 3.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of

				analysis used in its Real-time Assessments.
R4.	N/A	N/A	The responsible entity has an alarm process monitor but the alarm process monitor did not provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The responsible entity does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	October 30, 2015	New standard developed in Project 2009-02 to respond to recommendations in Real-time Best Practices Task Force Report and FERC directives.	N/A
1	May 5, 2016	Adopted by the Board of Trustees	New

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability Standards. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

<u>Requirement R1</u>

The TOP uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform monitoring and Real-time Assessments appear in other Reliability Standards.

The TOP's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the TOP shall include actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The TOP's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the TOP to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the TOP;
- Following processes established for resolving data conflicts as specified in TOP-003-3, or other applicable Reliability Standards;
- Taking corrective actions on the TOP's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the TOP's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R2

The BA uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability Standards.

The BA's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R2 Part 2.1. The criteria supports identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 specifies the BA shall include in its Operating Process or Operating Procedure actions to address Real-time data quality issues when data quality affects its analysis functions. Requirement R2 Part 2.3 is focused on addressing data point quality issues affecting analysis functions. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R2 Part 2.3.

The BA's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the BA to meet its obligations for performing its analysis functions. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the BA;

- Following processes established for resolving data conflicts as specified in TOP-003-3 or other applicable Reliability Standards;
- Taking corrective actions on the BA's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the BA's analysis functions; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the analysis quality so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R3

Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments may include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the types of criteria used to evaluate the quality of analysis used in Real-time Assessments may include solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R4

Requirement R4 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that a stall of the Real-time monitoring alarm processor does not cause a failure of the alarm process monitor.

Rationale

Rationale for Requirement R1: The Transmission Operator (TOP) uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the TOP shall include actions to address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2, provided that this process addresses Real-time data quality issues.

The revision in Part 1.3 to address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R2: The Balancing Authority (BA) uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 of this standard specifies the BA shall include actions to address Real-time data quality issues affecting its analysis functions in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2 provided that this process addresses Real-time data quality issues.

The revision in Part 2.3 to address Real-time data quality issues *when data quality affects its analysis functions* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R3: Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

Rationale for Requirement R4: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

Exhibit B

Implementation Plan

Implementation Plan

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Requested Approvals

- IRO-018-1 - Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
- TOP-010-1 - Real-time Reliability Monitoring and Analysis Capabilities

Requested Retirements

- None

Prerequisite Approval

- None

Revisions to Defined Terms in the NERC Glossary

None

Applicable Entities

- Reliability Coordinators
- Transmission Operators
- Balancing Authorities

Effective Date

IRO-018-1

- All Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, all Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

TOP-010-1

- All Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, all Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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 Standard has met or exceeded 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 specific reliability goals via sound methods. Proposed Reliability Standards IRO-018-1– Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities and TOP-010-1– Real-time Reliability Monitoring and Analysis Capabilities establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations. Reliability Standard IRO-018-1 addresses issues related to the quality and availability of Reliability Coordinator (RC) monitoring and analysis capabilities. Reliability Standard TOP-010-1 contains similar proposed requirements for Transmission Operators (TOPs) and Balancing Authorities (BAs).

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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 P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

Existing Reliability Standards contain functional requirements to perform Real-time monitoring and analysis. However, reliability would be improved by instituting requirements to provide operator awareness of monitoring, alarming, and analysis quality and tool availability to perform as intended.

Proposed Reliability Standards IRO-018-1 and TOP-010-1 would support effective Real-time monitoring and analysis and thereby enhance reliable operations by ensuring that: (i) operators are provided with indications of the quality of information being provided by monitoring and analysis capabilities; (ii) entities have procedures in place to identify and address high-priority data and analysis quality issues; and (iii) operators receive notifications during unplanned loss of alarming capabilities.

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]

Proposed Reliability Standard IRO-018-1 applies to Reliability Coordinators and is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The requirements clearly state who is required to comply with the standard.

Proposed Reliability Standard TOP-010-1applies to Transmission Operators and Balancing Authorities and is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The requirements clearly state who is required to comply with the standard.

3. A proposed Reliability Standard must include clear and understandable

[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRF") and Violation Severity Levels ("VSL") for each of the proposed standards comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding Requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. 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 and how the requirement will be enforced. These measures help provide clarity regarding how the requirements will be enforced, and ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard

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[4] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

[5] Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

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 address specific recommendations from a NERC technical committee relating to Real-time monitoring and analysis capabilities as well as certain Commission directives from Order No. 693.

The proposed Reliability Standards are technology neutral and complement existing functional requirements for Real-time monitoring and analysis contained in the TOP and IRO Reliability Standards approved by the Commission in Order No. 817. Proposed Reliability Standards IRO-018-1 and TOP-010-1 would improve Real-time situational awareness capabilities and thereby enhance reliable operations by requiring Reliability Coordinators, Transmission Operators, and Balancing Authorities to provide operators with awareness of monitoring and analysis capabilities, including alarm availability, so they may take appropriate steps to protect reliability.

The proposed standards would accomplish this as follows. First, the proposed standards would require entities to provide notification to operators of Real-time monitoring alarm failures. Second, the proposed standards would require entities to implement Operating Processes or Operating Procedures to: (i) provide operators with indication(s) of the quality of information being provided by their monitoring and analysis capabilities; and (ii) address deficiencies in the quality of information being provided by their monitoring and analysis capabilities. The proposed standards thus achieve their stated reliability goals effectively and efficiently.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System

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[6] Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

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 complement the rigorous functional requirements for Real-time monitoring and analysis in existing Reliability Standards by requiring applicable entities to provide operators with awareness of monitoring and analysis capabilities, including alarm availability, so they may take appropriate steps to protect reliability.

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.

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

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[7] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

[8] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational 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.

reliability.[9]

The proposed Reliability Standards do not 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 standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability.

The proposed 18 month implementation period for both Reliability Standards will allow applicable entities adequate time to ensure compliance with the requirements, including time to implement any upgrades to their Real-time monitoring systems. 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 and definitions were developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving

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[9] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

[10] Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

[11] Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to

Reliability Standards. **Exhibit H** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the standard.

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The additional and final ballots both 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 these proposed Reliability Standards. No comments were received that indicated the proposed Standards conflict 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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arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

[12] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[13] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

Violation Risk Factors and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justifications

Project 2009-02 Real-time Monitoring and Analysis Capabilities

This document provides the Standard Drafting Team's (SDT) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in Project 2009-02.

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 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.

FERC Violation Risk Factor Guidelines

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

The Commission seeks to ensure that VRFs 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 VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of VRFs 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 VRF 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

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

FERC's 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 Justification

The requirements in IRO-018-1 and TOP-010-1 were developed to address certain issues related to the Real-time monitoring and analysis capabilities used by operators of the BES. IRO-018-1 contains five requirements applicable to Reliability Coordinators (RCs), while TOP-010-1 contains seven analogous requirements for Transmission Operators (TOPs) and Balancing Authorities (BAs). A Medium VRF is proposed for all requirements in both standards according to the guidelines as explained below.

VRF Justifications – IRO-018-1 (R1-R3) and TOP-010-1 (R1-R4)	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A. The requirements are not directly connected to conclusions from the 2003 Blackout, but rather address specific recommendations from NERC Technical Committees.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard. The requirements have no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. These are new requirements. The VRFs in IRO-018-1 are consistent with those contained in TOP-010-1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A VRF of Medium is consistent with the NERC VRF definition. The requirements in IRO-018-1 and TOP-010-1 address issues related to the quality and availability of monitoring and analysis capabilities used by RCs, TOPs, and BAs in maintaining reliable operations. Violation of any of these requirements could directly affect the ability to effectively monitor and control the Bulk Electric System. However, violation of any of these requirements is unlikely to lead to Bulk Electric System instability, separation, or cascading failures. Therefore, a VRF of Medium is appropriate.

VRF Justifications – IRO-018-1 (R1-R3) and TOP-010-1 (R1-R4)	
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. Each requirement contains one objective, therefore a single VRF is assigned to each requirement.

VSL Justification

Proposed VSLs – IRO-018-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to

			perform its Real-time monitoring and Real-time Assessments.

VSL Justifications – IRO-018-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – IRO-018-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 2.1 through Part 2.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any

	of the elements listed in Part 2.1 through Part 2.3.		of the elements listed in Part 2.1 through Part 2.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.

VSL Justifications – IRO-018-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to 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 proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – IRO-018-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator has an alarm process monitor but	The Reliability Coordinator does not have an alarm process

		the alarm process monitor did not provide a notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

VSL Justifications – IRO-018-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time

	monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.

VSL Justifications – TOP-010-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 through Part 2.3.	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include two of the elements listed in Part 2.1 through Part 2.3.	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.

VSL Justifications – TOP-010-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.

FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4	The proposed VSL is not based on a cumulative number of violations.

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

Proposed VSLs – TOP-010-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 through Part 3.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.

VSL Justifications – TOP-010-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL is worded consistently with the corresponding requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity has an alarm process monitor but the alarm process monitor did not provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The responsible entity does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

VSL Justifications – TOP-010-1, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.

FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4	The proposed VSL is not based on a cumulative number of violations.

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

Exhibit E

Consideration of Directives

Order No. 693 Citation	Directive/Guidance	Resolution
P 905-906	Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.	Proposed IRO-018-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the Reliability Coordinator's (RC) monitoring and analysis capabilities. The monitoring and analysis capabilities required by proposed IRO-018-1 and other IRO standards discussed below ensure RCs have the capabilities to maintain Real-time situational awareness. **<u>Monitoring Capabilities</u>** Requirement R1 addresses the quality of the Real-time data needed by the RC to perform its monitoring and Real-time Assessments. Each RC is required to implement a documented procedure for addressing Real-time data quality issues. The procedure must include criteria for evaluating Real-time data quality, provisions for indicating data quality to the System Operator, and actions to address Real-time data quality issues when data quality affects Real-time Assessments. Requirement R3 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring RCs to use an alarm process monitor. Requirements for the RC to perform Real-time monitoring are specified in IRO-002-2, IRO-002-4, and IRO-003-2. ***Proposed IRO-018-1*** **R1.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time

Order No. 693 Citation	Directive/Guidance	Resolution
		monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating the quality of Real-time data; **1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and **1.3.** Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. **R3.** Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***IRO-002-2*** **R5.** Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. ***IRO-003-2*** **R1.** Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or

Order No. 693 Citation	Directive/Guidance	Resolution
		unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. ***IRO-002-4*** **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. **<u>Analysis Capabilities</u>** Requirement R2 addresses the quality of the analysis used by the RC to perform its Real-time Assessments. Each RC is required to implement a documented procedure to address the quality of the analysis used in its Real-time Assessments. The procedure must include criteria for evaluating the quality of analysis used in Real-time Assessments, provisions for indicating the quality of analysis, and actions to address analysis quality issues affecting its Real-time Assessments. Requirements for the RC to perform Real-time Assessments are specified in IRO-008-1 and IRO-008-2. ***Proposed IRO-018-1*** **R2.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include:

Order No. 693 Citation	Directive/Guidance	Resolution
		2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments; **2.2** Provisions to indicate the quality of analysis used in its Real-time Assessments; and **2.3.** Actions to address analysis quality issues affecting its Real-time Assessments. ***IRO-008-1*** **R2.** Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. ***Definition of 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.) ***IRO-008-2*** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Order No. 693 Citation	Directive/Guidance	Resolution
P 1660	We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.	Proposed TOP-010-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the monitoring and analysis capabilities used by Transmission Operators (TOPs) and Balancing Authorities (BAs). The monitoring and analysis capabilities required by TOP-010-1 and other TOP standards discussed below ensure TOPs and BAs have the capabilities to maintain Real-time situational awareness. **<u>Monitoring Capabilities</u>** Requirements R1 and R2 address the quality of the Real-time data needed by TOPs and BAs to perform their Real-time monitoring and Real-time analysis. Each TOP and BA is required to implement a documented procedure for addressing Real-time data quality issues. The procedure must include criteria for evaluating Real-time data quality, provisions for indicating data quality to the System Operator, and actions to address Real-time data quality issues when data quality affects analysis. Requirement R4 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring TOPs and BAs to use an alarm process monitor. Requirements for TOPs to perform Real-time monitoring are specified in TOP-001-3 and TOP-006-2. Requirements for BAs to perform Real-time monitoring are specified in TOP-006-2, TOP-001-3k and BAL standards. ***Proposed TOP-010-1*** **R1.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time

Order No. 693 Citation	Directive/Guidance	Resolution
		monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating the quality of Real-time data; **1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and **1.3.** Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. **R2.** Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: **2.1** Criteria for evaluating the quality of Real-time data; **2.2** Provisions to indicate the quality of Real-time data to the System Operator; and **2.3** Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data. **R4.** Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***TOP-006-2*** **R1.** Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

Order No. 693 Citation	Directive/Guidance	Resolution
		1.1. - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2.** - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. ***TOP-001-3*** **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. **<u>Analysis Capabilities</u>** Requirement R3 addresses the quality of the analysis used by the TOP to perform its Real-time Assessments. Each TOP is required to implement a documented procedure to address the quality of the analysis used in its Real-time Assessments. The procedure must include criteria for evaluating the quality of

Order No. 693 Citation	Directive/Guidance	Resolution
		analysis used in Real-time Assessments, provisions for indicating the quality of analysis, and actions to address analysis quality issues affecting its Real-time Assessments. Requirements for the TOP to perform Real-time Assessments are specified in TOP-003-3. ***Proposed TOP-010-1*** **R3.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: **3.1.** Criteria for evaluating the quality of any analysis used in its Real-time Assessments; **3.2.** Provisions to indicate the quality of analysis used in its Real-time Assessments; and **3.3.** Actions to address analysis quality issues affecting its Real-time Assessments. ***Definition of 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.) ***TOP-001-3*** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Order No. 693 Citation	Directive/Guidance	Resolution
P 1875	...[w]e direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1 to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.	The directive was considered in developing the scope of Project 2009-02. NERC believes TOP, IRO, and VAR standards address the directive as discussed below. Accordingly, additional requirements were not developed in Project 2009-02. RCs and TOPs are required to periodically perform Real-time Assessments consisting of an evaluation of system conditions "to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions." Entities must use whatever analysis is necessary to obtain an evaluation of system conditions, which may include real-time voltage stability analysis. Real-time Assessments assist operators in maintaining operations within established SOLs and IROLs, to include voltage stability criteria. Requirements for performing Real-time Assessments are contained in IRO-008-1, IRO-008-2, and TOP-001-3 Reliability Standards as discussed above. VAR-001-1 was revised in Project 2013-04. The resulting standard, VAR-001-4, did not include an explicit requirement for periodic performance of voltage stability analysis because "such analysis would be performed pursuant to the SOL methodology developed under FAC standards."[1] VAR-001-4 requirement R1 specifies the TOP must establish a system voltage schedule as part of its plan to operate within SOLs and IROLs. ***VAR-001-4*** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate

[1] Reliability Standard VAR-001-4.1, Guidelines and Technical Basis section, page 13. Available at: http://www.nerc.com/pa/Stand/Reliability%20Standards/VAR-001-4.1.pdf

Order No. 693 Citation	Directive/Guidance	Resolution
		within System Operating Limits and Interconnection Reliability Operating Limits. **1.1.** Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

Exhibit F

Standard Authorization Request Justification, Project 2009-02 Real-time Monitoring and Analysis Capabilities

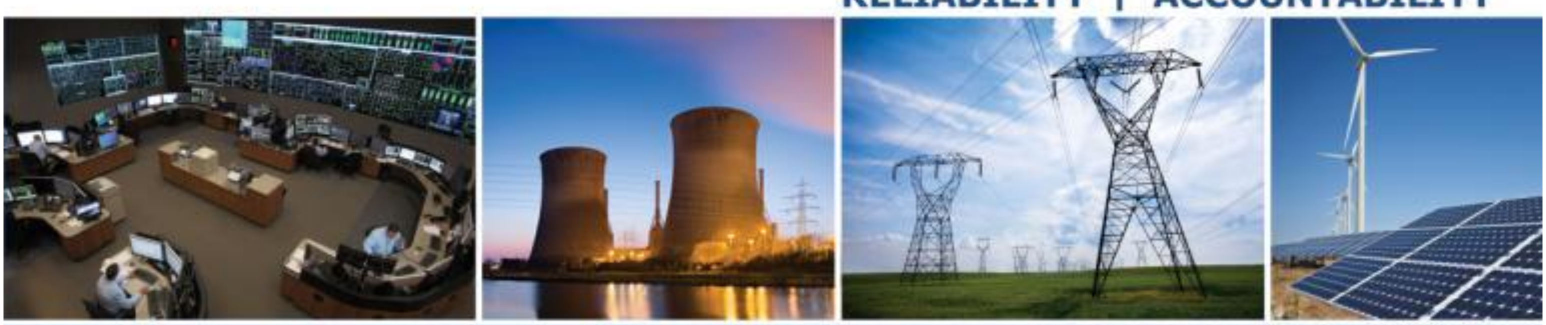
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Justification

Project 2009-02 Real-time Monitoring and Analysis Capabilities

RELIABILITY | ACCOUNTABILITY



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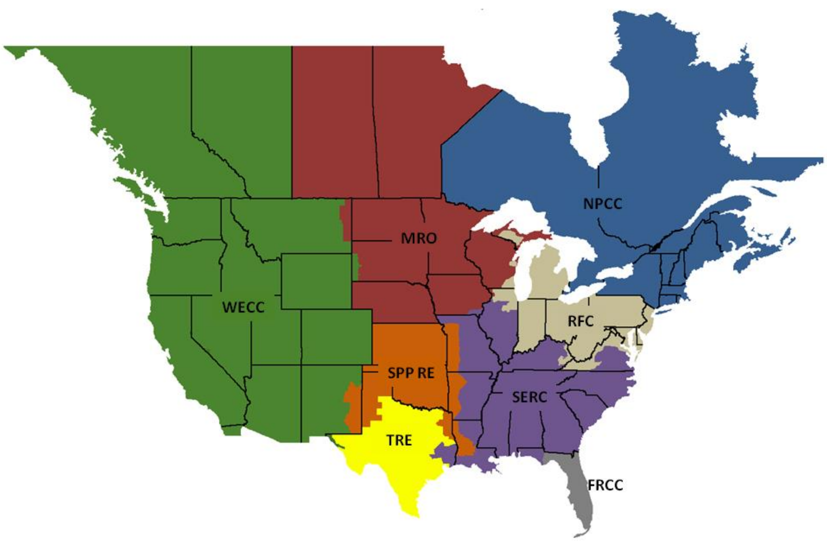
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

In April 2015, the Standards Committee appointed a new Standards Authorization Request (SAR) Drafting Team (SAR DT) for Project 2009-02 Real-time Monitoring and Analysis Capabilities. This project originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). Several new Reliability Standards and defined terms have been approved or filed for approval in the years since Project 2009-02 was initiated, including the standards developed in Project 2014-03 Revisions to TOP and IRO Standards. As a result, many of the original issues identified by the RTBPTF for Project 2009-02 have been addressed. In addition, relevant observations and recommendations have emerged from more recent events on the Bulk Electric System (BES) and operating practices have evolved over time. The SAR DT has reviewed previous work done in Project 2009-02, new standards and defined terms, relevant industry report findings and recommendations including those contained in the 2011 Southwest Outage report, and industry observations and practices relevant to real-time situational awareness to assist in developing a comprehensive SAR.

This white paper describes the SAR DT's approach to developing the SAR and discusses the technical basis for developing Reliability Standards in Project 2009-02. This white paper and the associated SAR together are intended to fully describe the project purpose, industry need, and project scope.

Chapter 1 – Background

FERC Order No. 693[1] highlights the need for a minimum set of capabilities to be available to assist operators in making real-time decisions. The work done by the RTBPTF, which was formed by NERC in response to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, became the basis for the Real-time Monitoring and Analysis Capabilities (RTMAC) standards development project when it was initiated in 2009. Although Reliability Standards affecting the operating reliability of the Bulk Electric System (BES) have improved significantly over the years since first becoming mandatory in 2007, a reliability issue has persisted in the area of real-time situational awareness capabilities as highlighted in BES event reports and an independent review of the NERC Reliability Standards. A review of industry reports and recommendations pertaining to real-time monitoring and analysis capabilities is provided in this document and in the Appendix. These recommendations, along with the FERC Order No. 693 directives, describe the industry need for the current RTMAC standards project.

BES Event Reports

Project 2009-02, like some other Reliability Standards projects, is informed by the lessons learned from past outages. The two significant outages discussed below highlight issues in real-time situational awareness, among other reliability concerns. Many Communications (COM), Transmission Operations (TOP), and Interconnection Reliability Operations (IRO) standards have addressed event report recommendations to improve the way the BES is planned and operated. The scope of Project 2009-02 is intended to include remaining recommendations from the 2003 Blackout Report and the 2011 Southwest Outage Report that pertain to real-time monitoring and analysis capabilities.

2003 Blackout Report

The largest blackout in history to affect North America began on the afternoon of August 14, 2003 and disrupted over 61,800 Megawatts of electric load in the Northeastern U.S. and the Canadian province of Ontario. Severe impacts to electrical service lasted for nearly one week and an estimated 50 million people were affected. A comprehensive investigation conducted by U.S. and Canadian government and industry leaders identified a host of principal and contributing causes, including:

- Failure to maintain adequate reactive power support,
- Failure to ensure operation within secure limits,
- Inadequate vegetation management,
- Inadequate operator training,
- Failure to identify emergency conditions and communicate that status to neighboring systems, and
- Inadequate regional-scale visibility over the Bulk-Power System (BPS).

Among other causes, the 2003 blackout was linked to dysfunction of SCADA/EMS systems. Additionally, investigators pointed out that several deficiencies leading to the 2003 blackout were also identified weaknesses in previous outages, indicating the need for more effective response. Previous post-event reports included recommendations aimed at improving capabilities for visualizing changes to facilities within the system, and for visualizing changes to facilities in neighboring systems that could have a potential impact. A recurring recommendation also focused on providing capabilities for operators to evaluate courses of action. These

[1] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, 72 Fed. Reg. 16416 at P 1660 (Apr. 4, 2007), FERC Stats. And Regs.¶ 31,242, *order on reh'g,* Order No. 693-A, 120 FERC ¶ 61,053 (2007) (Order No. 693).

observations led to the recommendation in the final report of the 2003 blackout for NERC to **evaluate and adopt better real-time tools for operators and reliability coordinators.**[2]

In response, the NERC Operating Committee organized the RTBPTF to study the real-time situational awareness practices in use within the electric power industry and make recommendations concerning the establishment of minimum capabilities necessary for reliable operations. The RTBPTF report *Real-time Tools Survey Analysis and Recommendations,*[3] completed in 2008, is the result of extensive information gathering and analysis and includes recommendations for new or enhanced Reliability Standards, operating guides, and areas for further analysis. This report became a basis for initiating the Real-time Monitoring and Analysis Capabilities project in 2009.

Although exhaustive and comprehensive, some of the RTBPTF recommendations go beyond the scope of situational awareness monitoring and capabilities. In addition, many other recommendations have been addressed in other subsequent standards projects. The appendix provides a description of RTBPTF report recommendations and the SAR DT's determination of applicability within the scope of Project 2009-02.

An early Concept White Paper describing potential performance, availability, quality, and maintenance parameters based on the RTBPTF Report was developed in 2011. The SAR DT reviewed the white paper and confirmed that, due to significant changes to Reliability Standards and operating practices since it was drafted, the 2011 Concept White Paper is no longer relevant to the current effort in Project 2009-02.

2011 Southwest Outage Report

Like the 2003 blackout in the northeast, the blackout that occurred in the southwest in September 2011 was partly due to, or exacerbated by, inadequate real-time situational awareness. On the afternoon of September 8, 2011, the loss of a single 500 kV line led to widespread cascading outages affecting 2.7 million customers in Arizona, Southern California, and Baja, Mexico. Inadequate operations planning was a significant factor in the failure to maintain a secure N-1 state. However, the report also highlighted several concerns with entities and their ability to monitor, identify, and plan for the next most critical contingency in real-time.[4]

Project 2014-03 - Revisions to TOP and IRO Standards addressed many of the recommendations contained in the 2011 Southwest Outage Report related to operations planning and real-time situational awareness. A complete description is provided in the Southwest Outage Report mapping document for Project 2014-03.[5] Revised definitions and performance requirements for Real-time Assessments and Operational Planning Analysis and proposed requirements for developing and implementing Operating Plans to prevent and mitigate operating limit exceedances address most of the real-time situational awareness recommendations from the report. However some recommendations contain aspects pertaining to real-time capabilities that should be considered in Project 2009-02, as described in the appendix. Accordingly, Project 2009-02 will develop requirements to address remaining recommendations as described in the following chapter.

[2] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* Recommendation 22, available at http://www.nerc.com/pa/rrm/ea/2003%20Blackout%20Final%20Report/Forms/AllItems.aspx.

[3] *Real-Time Tools Survey Analysis and Recommendations* (March 13, 2008), available at http://www.nerc.com/comm/OC/Realtime%20Tools%20Best%20Practices%20Task%20Force%20RTBPTF%2020/Real-Time%20Tools%20Survey%20Analysis%20and%20Recommendations.pdf.

[4] *Arizona-Southern California Outages on September 8, 2011* (April 2012), available at http://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf.

[5] See the project page for 2014-03, available at http://www.nerc.com/pa/stand/pages/project-2014-03-revisions-to-top-and-iro-standards.aspx.

FERC Directives

In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to operators.[6] FERC indicated that the intent of the directive is to ensure operating entities have adequate tools to perform their real-time reliability functions.[7]

- P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.*
- P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.*
- P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.*

Independent Experts Review Project (IERP) Report

In 2013, NERC retained a team of five industry experts to assess the quality of the enforceable body of standards and make recommendations for improvements that could be implemented by NERC and the industry.[8] Among the recommendations made by the panel of experts was the identification of potential risks to reliability that may not be adequately addressed in Reliability Standards. The report recommended resuming development of the Real-time Monitoring and Analysis Capabilities standards project.

Proposed TOP and IRO Standards

Since Project 2009-02 was initiated in 2009, many standards and definitions have been revised or developed that address real-time situational awareness issues. In particular, the revised TOP and IRO standards in Project 2014-03, which are pending regulatory approval, include key provisions for real-time situational awareness and operations planning. In reviewing the RTBPTF report recommendations for applicability in the current Project 2009-02 effort, the SAR DT considered the Project 2014-03 standards as noted in the Appendix.

The proposed TOP and IRO standards in Project 2014-03 provide requirements for performing monitoring and analysis through the definition of Real-time Assessment, Operational Planning Analysis, and the relevant requirements. Accordingly, additional requirements to perform monitoring or analysis will not be included in the scope for Project 2009-02. Furthermore, requirements for data exchange to support real-time monitoring and analysis will not be included in scope for Project 2009-02 because they are addressed through data specification requirements in IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3.

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[6] Order No. 693 at P 905 (approving IRO-002-1 and directing modifications) and P 1665 (approving TOP-006-1 and directing modifications.

[7] Additionally, in approving VAR-001-1 - Voltage and Reactive Control, the Commission directed NERC to develop modifications to the standard to require periodic performance of voltage stability analysis to assist in real-time operations. The commission clarified that this could be accomplished through online tools where available, or offline simulation tools.

- §1875: *...[w]e direct the ERO, through its Reliability Standards development process, ...to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.*

VAR-001 was revised in the Project 2013-04, however the revised standard did not include a requirement for periodic performance of voltage stability analysis because voltage stability analysis is performed per SOL Methodology developed under FAC standards.

[8] See The Standards Independent Experts Review Project report. Available at www.nerc.com /pa/Stand/_layouts/xlviewer.aspx?id=/pa/Stand/Documents/P81_and%20IERP_Recommendations_for_Retirement_010815.xlsx.

Technical Conference

NERC and the SAR DT held a Technical Conference in Atlanta on June 4, 2015, to obtain industry input on reliability issues to be addressed in the proposed project. Participant subject matter experts representing a diverse mix of regional and functional entities shared their perspectives on the use of real-time situational awareness capabilities for reliable operations. There was consensus that many RTBPTF recommendations have been addressed in current or proposed TOP and IRO standards. However, Technical Conference participants agreed that issues identified by the RTBPTF pertaining to availability and information quality of real-time monitoring and analysis capabilities were still relevant.

Chapter 2 – Project Scope

The SAR DT has reviewed all recommendations from the RTBPTF and relevant recommendations from event reports, along with the existing body of standards, to identify remaining issues that should be in the scope for Project 2009-02. Table 1 below shows the resulting recommendations to be addressed. Additionally, the project will address outstanding FERC directives discussed in the preceding chapter.

Table 1: Report Recommendations to Address in Project 2009-02

Source	Recommendation	Discussion	Applicable Entity
2003 Blackout Report	Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators.	Project 2009-02 will develop requirements for real-time reliability monitoring and analysis capabilities to address issues not already addressed in other Reliability Standards. RTBPTF report recommendations will be considered in development.	RC, TOP, BA
2011 Southwest Outage Report	Recommendation 12 - [entities] should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2009-02 will develop requirements to improve the adequacy and operation of real-time monitoring and analysis capabilities. Requirements addressing the frequency that real-time tools run are contained in other standards and are not in the scope of this project.	RC, TOP, BA
RTBPTF Report	S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • Alarm Tools • Telemetry Data Systems • Network Topology Processor • State Estimator • Contingency Analysis	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. Prescription of specific tools is not in scope. Project approach is discussed below.	RC, TOP, BA as discussed below
RTBPTF Report	S7 - S8, S11-S12, S40 - Availability of various monitoring and analysis capability processes	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring capabilities are not available (i.e., not performing their intended function).	RC, TOP, BA

Project Purpose and Approach

Project 2009-02 will develop requirements for real-time monitoring and analysis capabilities used by operators in support of reliable System operations. Functional requirements for performing *monitoring* and *analysis* tasks are well established in Reliability Standards as discussed throughout this white paper. However, reliability could be improved by:

- Developing a common understanding of *monitoring* as it applies to real-time situational awareness of the BES,
- Providing operators with indication(s) of the quality of information being provided by *monitoring* and *analysis* capabilities, and
- Providing operators with notification(s) during unplanned loss of *monitoring* capabilities.

Project 2009-02 will develop requirements and definition(s), as needed, to accomplish these reliability objectives as discussed.

Real-time Situational Awareness Concept

From the RTBPTF Report:

> *Situational awareness, as RTBPTF understands it, means ensuring that accurate information on current system conditions, including the likely effects of future contingencies, is continuously available in a form that allows operators to quickly grasp and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations.*

The Project 2009-02 SAR DT believes that situational awareness encompasses two broad capabilities: monitoring and analysis. To be effective in supporting real-time situational awareness, monitoring and analysis must:

- Be performed with sufficient frequency to allow operators to understand operating conditions and take corrective actions when necessary,
- Provide awareness of information quality to allow operators to assess the accuracy of information being received on system conditions and take corrective actions when necessary, and
- Indicate when monitoring or analysis processes are not operating normally or are unavailable in order to provide operator awareness of the accuracy of the information being provided.

Project 2009-02 will develop new requirements and definition(s), as needed, that support this concept of situational awareness without duplicating aspects that are already addressed in the existing and proposed body of Reliability Standards. As discussed in the preceding chapter, requirements for the Reliability Coordinator (RC), Transmission Operator (TOP), and Balancing Authority (BA) to perform monitoring and analysis are covered under existing and proposed TOP and IRO standards. Therefore, Project 2009-02 will focus on developing requirements to address information quality and operator awareness of real-time monitoring and analysis capabilities. Table 2 shows reliability objectives that should be addressed in requirements for this project.

Monitoring

Monitoring BES facilities in real-time is a primary function of the RCs, TOPs, and BAs and is addressed in existing and proposed TOP and IRO standards. For RCs, proposed IRO-002-4 states:

> *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.*

For TOPs and BAs, proposed TOP-001-3 states:

> *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.*

The SAR DT understands *monitoring* capabilities may include both alarming and information visualization. Project 2009-02 will aim to develop a consistent understanding of *monitoring* within the industry. The project will also address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of information being provided by a monitoring system, and indication when a monitoring system is not operating normally.

Analysis

The *analysis* component of the Real-time situational awareness concept is described by the definition of Real-time Assessment, which is pending FERC approval along with the proposed TOP and IRO standards. The proposed definition is as follows:

> ***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.)*

Requirements for performing Real-time Assessments are contained in proposed IRO-008-2 and TOP-001-3:

> ***Proposed IRO-008-2***
> *R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.*

> ***Proposed TOP-001-3***
> *R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.*

The SAR DT believes the proposed definition of Real-time Assessment and the requirements in proposed IRO-008-2 and TOP-001-3 provide RCs and TOPs with flexibility to determine which real-time tools, such as State Estimator, Contingency Analysis, and Stability Applications, are necessary to meet their real-time reliability functions. Consequently, prescriptive requirements for real-time tools are not in scope for Project 2009-02.

The project will address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of the analysis used in Real-time Assessments.

Table 2: Project 2009-02 Reliability Objectives

	Monitoring Capabilities	Analysis Capabilities
Quality	Provide operator with indication of information quality and procedures to address data quality issues.	Provide operator with indication of information quality and procedures to address analysis quality issues.
Availability	Provide operator with notification any time monitoring system is not operating normally.	N/A

Appendix – Report Recommendations

The table below contains recommendations for improved real-time situational awareness capabilities found in relevant industry reports and how these recommendations have been addressed, if applicable. If recommendations have not been addressed fully, the table includes a description of how they should be addressed in Project 2009-02. The following industry reports are considered here[9]:

- 2003 Blackout Final Report
- 2011 Southwest Outage Report
- Real-time Tools Best Practices Task Force

Report Recommendation Mapping	
Report Recommendation	**Applicable Standard(s)**
2003 Blackout Final Report	
Recommendation 1-21, 23-46	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators. Operating Committee to evaluate the real-time operating tools necessary for reliability operation and reliability coordination, including backup capabilities. The committee's report is to address both minimum acceptable capabilities for critical reliability functions and a guide to best practices.	The Operating Committee established the RTBPTF to evaluate real-time operating tools and make recommendations for proposed standards. Project 2009-02 should consider these recommendations as discussed below.
2011 Southwest Outage Report	
Recommendation 1-10, 13-26	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 11 - TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Project 2014-03 developed the proposed definition of Real-time Assessment and proposed TOP-003-3 Requirement R1 which describes the requirements for a data specification that will provide all of the data that a TOP needs in order to fulfill its reliability function. Together, these address capabilities and required data TOPs must have to ensure adequate situational awareness. **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.) **Proposed TOP-003-3, Requirement R1, Part 1.1**:

[9] *All industry reports are available on the 2009-02 Project Page: http://www.nerc.com/pa/Stand/Pages/Project-2009-02-Real-time-Reliability-Monitoring-and-Analysis-Capabilities.aspx.*

	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.
Recommendation 12 - TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2014-03 developed a requirement for the performance of a Real-time Assessment for Transmission Operators. Standards developed in Project 2009-02 will address the adequacy of tools as described in this recommendation. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
Recommendation 27 - TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences.	Proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA) developed in Project 2014-03 specify that identified phase angle limitations must be considered and deal with applying phase angle information. Proposed TOP-002 Requirement R2 specifies that TOPs must have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified in the OPA. Data specification requirements in approved IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3 provide a means for RCs and TOPs to obtain phase angle information. **Proposed Definition: 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.) **Proposed Definition: 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.) **Proposed TOP-002-4** 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.
RTBPTF Report	
S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • **Alarm Tools** • **Telemetry Data Systems** • **Network Topology Processor** • **State Estimator** • **Contingency Analysis**	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. However, prescription of specific tools is not in scope.
S2 - Compile and maintain a list of all bulk electric system elements within RC's area of responsibility.	Not in scope. Reliability objective is accomplished through monitoring and analysis requirements as discussed below.
S3 - Add new requirements and measures pertaining to RC monitoring of the bulk electric system.	Addressed in IRO standards (current and proposed). **IRO-002-2** R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. **IRO-003-2** R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. **Proposed IRO-002-4** 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.
S4 - Develop data-exchange standards.	Addressed in proposed TOP-001-3 and IRO-002-4. **Proposed TOP-001-3** R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area. R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it

	needs data from in order to maintain reliability in its Balancing Authority Area. **Proposed IRO-002-4** 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.
S5 - Develop data-availability standards and a process for trouble resolution and escalation.	Data availability and trouble resolution is addressed in IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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.
S6 - Develop a new weather data requirement related to situational awareness and real-time operational capabilities.	EOP-010-1 covers space weather dissemination. The SAR DT views monitoring other weather information as common utility practice that does not require a reliability standard.
S7 - Specify and measure minimum availability for alarm tools.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the

	RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function). Availability notification for analysis tools is addressed in IRO-008-1, and proposed IRO-008-2 proposed TOP-001-3 from Project 2014-30. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed IRO-008-2** R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
S8 - Specify and measure minimum availability for network topology processor.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S9 - Establish a uniform formal process to determine the "wide area view boundary" and show boundary data/results.	Wide-area is now a defined term. Recommendation has been addressed.
S10 - Develop compliance measures for verification of the usage of "wide-area overview display" visualization tools.	IRO standards revisions have addressed compliance measures.
S11 - Specify and measure minimum availability for state estimator, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S12 - Specify and measure minimum availability for contingency analysis, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S13 - Specify criteria and develop measures for defining contingencies.	Not in scope; Addressed in approved TPL and FAC standards.
S14 - Perform one-hour-ahead power-flow simulations to assess approaching SOL and IROL violations and corresponding measures.	Requirements for assessing pre- and post-contingency system conditions are addressed in Real-time Assessment (RTA) and Operational Planning Analysis (OPA) definitions. Requirements for performing RTA and OPA are contained in

	proposed TOP-001-3, TOP-002-4, IRO-008-2, and approved IRO-008-1. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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. R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed definition** **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.) **Proposed definition** **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.)
S15 - Provide real-time awareness of load-shed capability to address potential or actual IROL violations.	Addressed in proposed EOP-011-1, approved IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

	2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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.
S16 - Require BAs to monitor contingency reserves and calculate contingency reserves at a minimum periodicity of 10 seconds.	BA responsibilities for managing Contingency Reserve are addressed in the approved BAL-002-1 standard which is under revision in Project 2010-014. 1. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.
S17 - Revise the current-day operations requirements to delineate specific, independent requirements for monitoring operating and reactive reserves.	Addressed in VAR-001-4, BAL-002, and proposed IRO-002-4 and TOP-001-3. **VAR-001-4** R4. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. **Proposed IRO-002-4** **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. **Proposed TOP-001-3** 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.
S18 - Establish document plans and procedures for conservative operations.	Addressed in proposed EOP-011-1 Requirement R1. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating

	Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

S19 - Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes.	Addressed in proposed TOP-001-3, and IRO-008-2 and the proposed definitions for Operational Planning Analysis and Real-time Assessment. **Proposed TOP-001-3** R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. 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 an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-008-2** 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. **Proposed definition** **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.) **Proposed definition** **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.)
S20 - Develop formal operating guides (mitigation plans) and measures for each IROL and any SOL or other conditions having a potential impact on reliability.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S21 - Review and update operating guides (mitigation plans) **when day-ahead or current day studies indicate the potential need to implement an operating guide.**	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S22 - Provide temporary operating guides (mitigation plans) with control actions for situations that could affect reliability but that have not been identified previously.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S23 - Develop joint operating guides (mitigation plans) for situations that could require more than one RC or more than one TOP to execute actions.	Addressed in IRO-014-2, proposed IRO-014-3 and proposed IRO-008-2. **IRO-014-2** R1. Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall collectively address the following: ... **Proposed IRO-014-3** 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: ... **Proposed IRO-008-2** 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.
S24 - Develop a formal procedure to document the processes for developing, reviewing, and updating operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S25 - Incorporate verifiable and traceable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates when modifying operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S26 - Write operating guides (mitigation plans) in clear, unambiguous language, leaving nothing to interpretation.	Not in scope. This is administrative in nature.
S27 - State the specific purpose of existence for each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S28 - Summarize the specific situation assessment and address the method of performing the assessment in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S29 - Identify all appropriate preventive and remedial control actions in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S30 - Develop criteria in operating guides (mitigation plans) to support decisions regarding whether a specific control action should be taken.	Not in scope. This is administrative in nature.
S31 - Incorporate on-line tools that utilize on-line data when operating guides (mitigation plans) require calculations.	Not in scope. Recommendation is appropriate as a guideline rather than a reliability standard.
S32 - Make operating guides (mitigation plans) readily available via a quick-access method such as Web-based help, EMS display notes, or on-line help systems.	Not in scope. This is administrative in nature.
S33 - Provide the location, real-time status, and MWs of load available to be shed.	Addressed in proposed EOP-011-1 Requirement R1 Part 1.2.5 and proposed TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

	1.2.6. Reliability impacts of extreme weather conditions. **Proposed TOP-003-3** 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. ...
S34 - Establish documented procedures for the reassessment and re-posturing of the system following an event.	Addressed in proposed TOP-002-4 and IRO-008-2, and approved EOP-005-2 and EOP-006-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ...

	EOP-006-2 R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S35 - Provide information to operators to maintain awareness of the availability and capability of the blackstart generators and transmission restoration paths.	Addressed in approved IRO-010-1, proposed TOP-003-3, proposed IRO-010-2, approved EOP-005-2, and approved EOP-006-2. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... R1.6. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ... R1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit. ... R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **EOP-006-2** R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S36 - Plan and coordinate scheduled outages of blackstart generators and transmission restoration paths.	Addressed in approved EOP-005-2 and proposed IRO-017-1 - Outage Coordination. **EOP-005-2** R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **Proposed IRO-017-1** R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation

	and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: ...
S37 - Maintain a Critical Equipment Monitoring Document to identify tools and procedures for monitoring critical equipment.	Not in scope. This is administrative in nature.
S38 - Maintain event logs pertaining to critical equipment status for a period of one year.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be “installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools”. Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S39 - Maintain a Critical Equipment Maintenance and Testing Document identifying tools and procedures for maintenance, modification, and testing of critical equipment.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be “installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools”. Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S40 - Monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation.	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and analysis capabilities are not available (i.e., not performing their intended function).

Exhibit G

Reports Considered in Project 2009-02

Exhibit G-1

August 2003 Blackout Report

U.S.-Canada Power System Outage Task Force

Final Report on the August 14, 2003 Blackout in the United States and Canada:

Causes and Recommendations

April 2004

U.S.-Canada Power System Outage Task Force

Final Report on the August 14, 2003 Blackout in the United States and Canada:

Causes and Recommendations

Canada

April 2004

U.S.-Canada Power System Outage Task Force

March 31, 2004

Dear Mr. President and Prime Minister:

We are pleased to submit the Final Report of the U.S.-Canada Power System Outage Task Force. As directed by you, the Task Force has completed a thorough investigation of the causes of the August 14, 2003 blackout and has recommended actions to minimize the likelihood and scope of similar events in the future.

The report makes clear that this blackout could have been prevented and that immediate actions must be taken in both the United States and Canada to ensure that our electric system is more reliable. First and foremost, compliance with reliability rules must be made mandatory with substantial penalties for non-compliance.

We expect continued collaboration between our two countries to implement this report's recommendations. Failure to implement the recommendations would threaten the reliability of the electricity supply that is critical to the economic, energy and national security of our countries.

The work of the Task Force has been an outstanding example of close and effective cooperation between the U.S. and Canadian governments. Such work will continue as we strive to implement the Final Report's recommendations. We resolve to work in cooperation with Congress, Parliament, states, provinces and stakeholders to ensure that North America's electric grid is robust and reliable.

We would like to specifically thank the members of the Task Force and its Working Groups for their efforts and support as we investigated the blackout and moved toward completion of the Final Report. All involved have made valuable contributions. We submit this report with optimism that its recommendations will result in better electric service for the people of both our nations.

Sincerely,

U.S. Secretary of Energy

Minister of Natural Resources Canada

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1. Introduction

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and power was not restored for 4 days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the United States range between $4 billion and $10 billion (U.S. dollars).[1] In Canada, gross domestic product was down 0.7% in August, there was a net loss of 18.9 million work hours, and manufacturing shipments in Ontario were down $2.3 billion (Canadian dollars).[2]

On August 15, President George W. Bush and then-Prime Minister Jean Chrétien directed that a joint U.S.-Canada Power System Outage Task Force be established to investigate the causes of the blackout and ways to reduce the possibility of future outages. They named U.S. Secretary of Energy Spencer Abraham and Herb Dhaliwal, Minister of Natural Resources, Canada, to chair the joint Task Force. (Mr. Dhaliwal was later succeeded by Mr. John Efford as Minister of Natural Resources and as co-chair of the Task Force.) Three other U.S. representatives and three other Canadian representatives were named to the Task Force. The U.S. members were Tom Ridge, Secretary of Homeland Security; Pat Wood III, Chairman of the Federal Energy Regulatory Commission; and Nils Diaz, Chairman of the Nuclear Regulatory Commission. The Canadian members were Deputy Prime Minister John Manley, later succeeded by Deputy Prime Minister Anne McLellan; Kenneth Vollman, Chairman of the National Energy Board; and Linda J. Keen, President and CEO of the Canadian Nuclear Safety Commission.

The Task Force divided its work into two phases:

- Phase I: Investigate the outage to determine its causes and why it was not contained.
- Phase II: Develop recommendations to reduce the possibility of future outages and reduce the scope of any that occur.

The Task Force created three Working Groups to assist in both phases of its work—an Electric System Working Group (ESWG), a Nuclear Working Group (NWG), and a Security Working Group (SWG). The Working Groups were made up of state and provincial representatives, federal employees, and contractors working for the U.S. and Canadian government agencies represented on the Task Force.

The Task Force published an Interim Report on November 19, 2003, summarizing the facts that the bi-national investigation found regarding the causes of the blackout on August 14, 2003. After November 19, the Task Force's technical investigation teams pursued certain analyses that were not complete in time for publication in the Interim Report. The Working Groups focused on the drafting of recommendations for the consideration of the Task Force to prevent future blackouts and reduce the scope of any that nonetheless occur. In drafting these recommendations, the Working Groups drew substantially on information and insights from the investigation teams' additional analyses, and on inputs received at three public meetings (in Cleveland, New York City, and Toronto) and two technical conferences (in Philadelphia and Toronto). They also drew on comments filed electronically by interested parties on websites established for this purpose by the U.S. Department of Energy and Natural Resources Canada.

Although this Final Report presents some new information about the events and circumstances before the start of the blackout and additional detail concerning the cascade stage of the blackout, none of the comments received or additional analyses performed by the Task Force's investigators have changed the validity of the conclusions published in the Interim Report. This report, however, presents findings concerning additional violations of reliability requirements and institutional and performance deficiencies beyond those identified in the Interim Report.

The organization of this Final Report is similar to that of the Interim Report, and it is intended to update and supersede the Interim Report. It is divided into ten chapters, including this introductory chapter:

- Chapter 2 provides an overview of the institutional framework for maintaining and ensuring the reliability of the bulk power system in North America, with particular attention to the roles and responsibilities of several types of reliability-related organizations.
- Chapter 3 identifies the causes of the blackout and identifies failures to perform effectively relative to the reliability policies, guidelines, and standards of the North American Electric Reliability Council (NERC) and, in some cases, deficiencies in the standards themselves.
- Chapter 4 discusses conditions on the regional power system on and before August 14 and identifies conditions and failures that did and did not contribute to the blackout.
- Chapter 5 describes the afternoon of August 14, starting from normal operating conditions, then going into a period of abnormal but still potentially manageable conditions, and finally into an uncontrollable blackout in northern Ohio.
- Chapter 6 provides details on the cascade phase of the blackout as it spread in Ohio and then across the Northeast, and explains why the system performed as it did.
- Chapter 7 compares the August 14, 2003, blackout with previous major North American power outages.
- Chapter 8 examines the performance of the nuclear power plants affected by the August 14 outage.
- Chapter 9 addresses issues related to physical and cyber security associated with the outage.
- Chapter 10 presents the Task Force's recommendations for preventing future blackouts and reducing the scope of any that occur.

Chapter 10 includes a total of 46 recommendations, but the single most important of them is that the U.S. Congress should enact the reliability provisions in H.R. 6 and S. 2095 to make compliance with reliability standards mandatory and enforceable. If that could be done, many of the other recommended actions could be accomplished readily in the course of implementing the legislation. An overview of the recommendations (by titles only) is provided on pages 3 and 4.

Chapter 2 is very little changed from the version published in the Interim Report. Chapter 3 is new to this Final Report. Chapters 4, 5, and 6 have been revised and expanded from the corresponding chapters (3, 4, and 5) of the Interim Report. Chapters 7, 8, and 9 are only slightly changed from Chapters 6, 7, and 8 of the Interim Report. The Interim Report had no counterpart to Chapter 10.

This report also includes seven appendixes:

- Appendix A lists the members of the Task Force and the three working groups.
- Appendix B describes the Task Force's investigative process for developing the Task Force's recommendations.
- Appendix C lists the parties who either commented on the Interim Report, provided suggestions for recommendations, or both.
- Appendix D reproduces a document released on February 10, 2004 by NERC, describing its actions to prevent and mitigate the impacts of future cascading blackouts.
- Appendix E is a list of electricity acronyms.
- Appendix F provides a glossary of electricity terms.
- Appendix G contains transmittal letters pertinent to this report from the three Working Groups.

Overview of Task Force Recommendations: Titles Only

Group I. Institutional Issues Related to Reliability

1. Make reliability standards mandatory and enforceable, with penalties for noncompliance.
2. Develop a regulator-approved funding mechanism for NERC and the regional reliability councils, to ensure their independence from the parties they oversee.
3. Strengthen the institutional framework for reliability management in North America.
4. Clarify that prudent expenditures and investments for bulk system reliability (including investments in new technologies) will be recoverable through transmission rates.
5. Track implementation of recommended actions to improve reliability.
6. FERC should not approve the operation of new RTOs or ISOs until they have met minimum functional requirements.
7. Require any entity operating as part of the bulk power system to be a member of a regional reliability council if it operates within the council's footprint.
8. Shield operators who initiate load shedding pursuant to approved guidelines from liability or retaliation.
9. Integrate a "reliability impact" consideration into the regulatory decision-making process.
10. Establish an independent source of reliability performance information.
11. Establish requirements for collection and reporting of data needed for post-blackout analyses.
12. Commission an independent study of the relationships among industry restructuring, competition, and reliability.
13. DOE should expand its research programs on reliability-related tools and technologies.
14. Establish a standing framework for the conduct of future blackout and disturbance investigations.

Group II. Support and Strengthen NERC's Actions of February 10, 2004

15. Correct the direct causes of the August 14, 2003 blackout.
16. Establish enforceable standards for maintenance of electrical clearances in right-of-way areas.
17. Strengthen the NERC Compliance Enforcement Program.
18. Support and strengthen NERC's Reliability Readiness Audit Program.
19. Improve near-term and long-term training and certification requirements for operators, reliability coordinators, and operator support staff.
20. Establish clear definitions for *normal, alert* and *emergency* operational system conditions. Clarify roles, responsibilities, and authorities of reliability coordinators and control areas under each condition.
21. Make more effective and wider use of system protection measures.
22. Evaluate and adopt better real-time tools for operators and reliability coordinators.
23. Strengthen reactive power and voltage control practices in all NERC regions.
24. Improve quality of system modeling data and data exchange practices.
25. NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards.
26. Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate.
27. Develop enforceable standards for transmission line ratings.
28. Require use of time-synchronized data recorders.
29. Evaluate and disseminate lessons learned during system restoration.
30. Clarify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages.
31. Clarify that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit. Streamline the TLR process.

(continued on page 142)

Overview of Task Force Recommendations: Titles Only (Continued)

Group III. Physical and Cyber Security of North American Bulk Power Systems

32. Implement NERC IT standards.
33. Develop and deploy IT management procedures.
34. Develop corporate-level IT security governance and strategies.
35. Implement controls to manage system health, network monitoring, and incident management.
36. Initiate U.S.-Canada risk management study.
37. Improve IT forensic and diagnostic capabilities.
38. Assess IT risk and vulnerability at scheduled intervals.
39. Develop capability to detect wireless and remote wireline intrusion and surveillance.
40. Control access to operationally sensitive equipment.
41. NERC should provide guidance on employee background checks.
42. Confirm NERC ES-ISAC as the central point for sharing security information and analysis.
43. Establish clear authority for physical and cyber security.
44. Develop procedures to prevent or mitigate inappropriate disclosure of information.

Group IV. Canadian Nuclear Power Sector

45. The Task Force recommends that the Canadian Nuclear Safety Commission request Ontario Power Generation and Bruce Power to review operating procedures and operator training associated with the use of adjuster rods.
46. The Task Force recommends that the Canadian Nuclear Safety Commission purchase and install backup generation equipment.

Endnotes

[1] See "The Economic Impacts of the August 2003 Blackout," Electric Consumer Research Council (ELCON), February 2, 2004.

[2] Statistics Canada, *Gross Domestic Product by Industry*, August 2003, Catalogue No. 15-001; *September 2003 Labour Force Survey*; *Monthly Survey of Manufacturing*, August 2003, Catalogue No. 31-001.

2. Overview of the North American Electric Power System and Its Reliability Organizations

The North American Power Grid Is One Large, Interconnected Machine

The North American electricity system is one of the great engineering achievements of the past 100 years. This electricity infrastructure represents more than $1 trillion (U.S.) in asset value, more than 200,000 miles—or 320,000 kilometers (km) of transmission lines operating at 230,000 volts and greater, 950,000 megawatts of generating capability, and nearly 3,500 utility organizations serving well over 100 million customers and 283 million people.

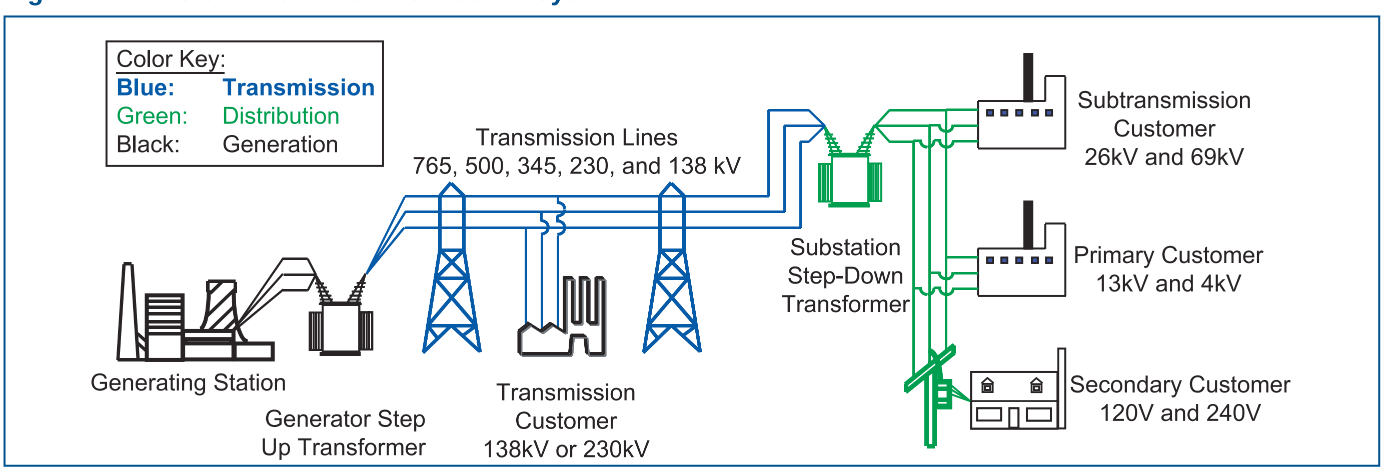
Modern society has come to depend on reliable electricity as an essential resource for national security; health and welfare; communications; finance; transportation; food and water supply; heating, cooling, and lighting; computers and electronics; commercial enterprise; and even entertainment and leisure—in short, nearly all aspects of modern life. Customers have grown to expect that electricity will almost always be available when needed at the flick of a switch. Most customers have also experienced local outages caused by a car hitting a power pole, a construction crew accidentally damaging a cable, or a lightning storm. What is not expected is the occurrence of a massive outage on a calm, warm day. Widespread electrical outages, such as the one that occurred on August 14, 2003, are rare, but they can happen if multiple reliability safeguards break down.

Providing reliable electricity is an enormously complex technical challenge, even on the most routine of days. It involves real-time assessment, control and coordination of electricity production at thousands of generators, moving electricity across an interconnected network of transmission lines, and ultimately delivering the electricity to millions of customers by means of a distribution network.

As shown in Figure 2.1, electricity is produced at lower voltages (10,000 to 25,000 volts) at generators from various fuel sources, such as nuclear, coal, oil, natural gas, hydro power, geothermal, photovoltaic, etc. Some generators are owned by the same electric utilities that serve the end-use customer; some are owned by independent power producers (IPPs); and others are owned by customers themselves—particularly large industrial customers.

Electricity from generators is "stepped up" to higher voltages for transportation in bulk over

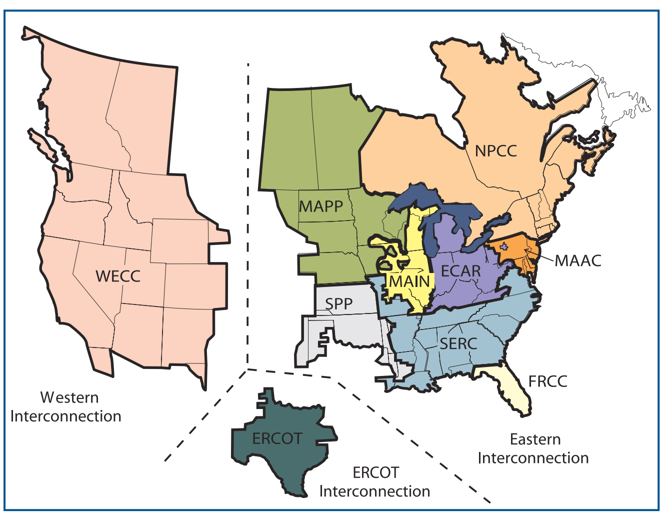
Figure 2.1. Basic Structure of the Electric System



transmission lines. Operating the transmission lines at high voltage (i.e., 230,000 to 765,000 volts) reduces the losses of electricity from conductor heating and allows power to be shipped economically over long distances. Transmission lines are interconnected at switching stations and substations to form a network of lines and stations called a power "grid." Electricity flows through the interconnected network of transmission lines from the generators to the loads in accordance with the laws of physics—along "paths of least resistance," in much the same way that water flows through a network of canals. When the power arrives near a load center, it is "stepped down" to lower voltages for distribution to customers. The bulk power system is predominantly an alternating current (AC) system, as opposed to a direct current (DC) system, because of the ease and low cost with which voltages in AC systems can be converted from one level to another. Some larger industrial and commercial customers take service at intermediate voltage levels (12,000 to 115,000 volts), but most residential customers take their electrical service at 120 and 240 volts.

While the power system in North America is commonly referred to as "the grid," there are actually three distinct power grids or "interconnections" (Figure 2.2). The Eastern Interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces. The Western Interconnection includes the western third of the continental United States (excluding Alaska), the Canadian provinces of Alberta and British Columbia, and a portion of Baja California Norte, Mexico. The third interconnection comprises most of the state of Texas. The three interconnections are electrically independent from each other except for a few small direct current (DC) ties that link them. Within each interconnection, electricity is produced the instant it is used, and flows over virtually all transmission lines from generators to loads.

Figure 2.2. North American Interconnections



The northeastern portion of the Eastern Interconnection (about 10 percent of the interconnection's total load) was affected by the August 14 blackout. The other two interconnections were not affected.[1]

Planning and Reliable Operation of the Power Grid Are Technically Demanding

Reliable operation of the power grid is complex and demanding for two fundamental reasons:

- First, electricity flows at close to the speed of light (186,000 miles per second or 297,600 km/sec) and is not economically storable in large quantities. Therefore electricity must be produced the instant it is used.
- Second, without the use of control devices too expensive for general use, the flow of alternating current (AC) electricity cannot be controlled like a liquid or gas by opening or closing a valve in a pipe, or switched like calls over a long-distance telephone network.[2] Electricity flows freely along all available paths from the generators to the loads in accordance with the laws of physics—dividing among all connected flow paths in the network, in inverse proportion to the impedance (resistance plus reactance) on each path.

Maintaining reliability is a complex enterprise that requires trained and skilled operators, sophisticated computers and communications, and careful planning and design. The North American Electric Reliability Council (NERC) and its ten Regional Reliability Councils have developed system operating and planning standards for ensuring the reliability of a transmission grid that are based on seven key concepts:

- Balance power generation and demand continuously.
- Balance reactive power supply and demand to maintain scheduled voltages.
- Monitor flows over transmission lines and other facilities to ensure that thermal (heating) limits are not exceeded.

- Keep the system in a stable condition.
- Operate the system so that it remains in a reliable condition even if a contingency occurs, such as the loss of a key generator or transmission facility (the "N-1 criterion").
- Plan, design, and maintain the system to operate reliably.
- Prepare for emergencies.

These seven concepts are explained in more detail below.

1. **Balance power generation and demand continuously.** To enable customers to use as much electricity as they wish at any moment, production by the generators must be scheduled or "dispatched" to meet constantly changing demands, typically on an hourly basis, and then fine-tuned throughout the hour, sometimes through the use of automatic generation controls to continuously match generation to actual demand. Demand is somewhat predictable, appearing as a daily demand curve—in the summer, highest during the afternoon and evening and lowest in the middle of the night, and higher on weekdays when most businesses are open (Figure 2.3).

   Failure to match generation to demand causes the frequency of an AC power system (nominally 60 cycles per second or 60 Hertz) to increase (when generation exceeds demand) or decrease (when generation is less than demand) (Figure 2.4). Random, small variations in frequency are normal, as loads come on and off and generators modify their output to follow the demand changes. However, large deviations in frequency can cause the rotational speed of generators to fluctuate, leading to vibrations that can damage generator turbine blades and other equipment. Extreme low frequencies can trigger automatic under-frequency "load shedding," which takes blocks of customers off-line in order to prevent a total collapse of the electric system. As will be seen later in this report, such an imbalance of generation and demand can also occur when the system responds to major disturbances by breaking into separate "islands"; any such island may have an excess or a shortage of generation, compared to demand within the island.

2. **Balance reactive power supply and demand to maintain scheduled voltages.** Reactive power sources, such as capacitor banks and generators, must be adjusted during the day to maintain voltages within a secure range pertaining to all system electrical equipment (stations, transmission lines, and customer equipment). Most generators have automatic voltage regulators that cause the reactive power output of generators to increase or decrease to control voltages to scheduled levels. Low voltage can cause electric system instability or collapse and, at distribution voltages, can cause damage to motors and the failure of electronic equipment. High voltages can exceed the insulation capabilities of equipment and cause dangerous electric arcs ("flashovers").

3. **Monitor flows over transmission lines and other facilities to ensure that thermal (heating) limits are not exceeded.** The dynamic interactions between generators and loads, combined with the fact that electricity flows freely across all interconnected circuits, mean that power flow is ever-changing on transmission and distribution lines. All lines, transformers, and other equipment carrying electricity are heated by the flow of electricity through them. The

Figure 2.3. PJM Load Curve, August 18-24, 2003

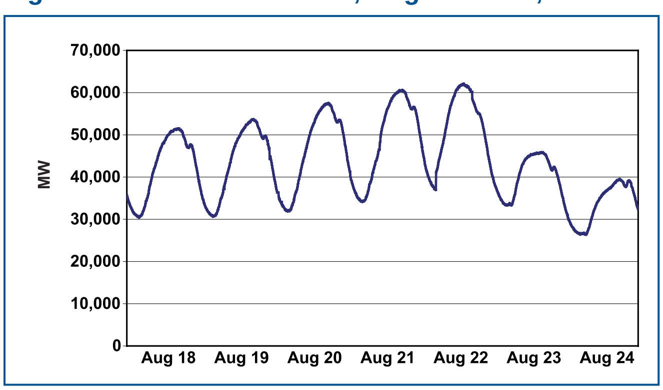
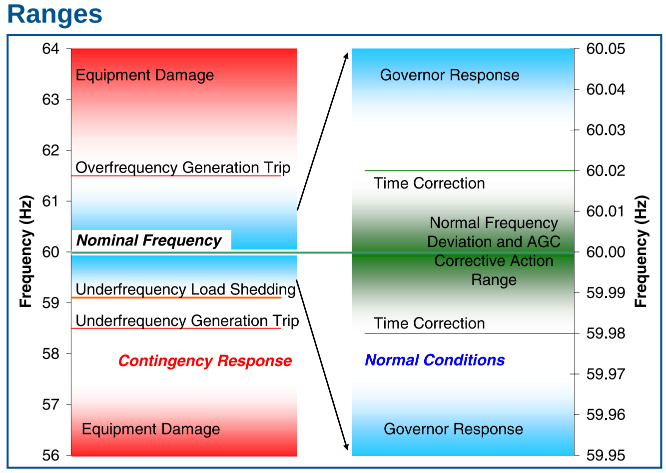


Figure 2.4. Normal and Abnormal Frequency Ranges



Local Supplies of Reactive Power Are Essential to Maintaining Voltage Stability

A generator typically produces some mixture of "real" and "reactive" power, and the balance between them can be adjusted at short notice to meet changing conditions. Real power, measured in watts, is the form of electricity that powers equipment. Reactive power, a characteristic of AC systems, is measured in volt-amperes reactive (VAr), and is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps, and air conditioning.) Transmission lines both consume and produce reactive power. At light loads they are net producers, and at heavy loads, they are heavy consumers. Reactive power consumption by these facilities or devices tends to depress transmission voltage, while its production (by generators) or injection (from storage devices such as capacitors) tends to support voltage. Reactive power can be transmitted only over relatively short distances during heavy load conditions. If reactive power cannot be supplied promptly and in sufficient quantity, voltages decay, and in extreme cases a "voltage collapse" may result.

flow must be limited to avoid overheating and damaging the equipment. In the case of overhead power lines, heating also causes the metal conductor to stretch or expand and sag closer to ground level. Conductor heating is also affected by ambient temperature, wind, and other factors. Flow on overhead lines must be limited to ensure that the line does not sag into obstructions below such as trees or telephone lines, or violate the minimum safety clearances between the energized lines and other objects. (A short circuit or "flashover"—which can start fires or damage equipment—can occur if an energized line gets too close to another object). Most transmission lines, transformers and other current-carrying devices are monitored continuously to ensure that they do not become overloaded or violate other operating constraints. Multiple ratings are typically used, one for normal conditions and a higher rating for emergencies. The primary means of limiting the flow of power on transmission lines is to adjust selectively the output of generators.

4. **Keep the system in a stable condition.** Because the electric system is interconnected and dynamic, electrical stability limits must be observed. Stability problems can develop very quickly—in just a few cycles (a cycle is 1/60th of a second)—or more slowly, over seconds or minutes. The main concern is to ensure that generation dispatch and the resulting power flows and voltages are such that the system is stable at all times. (As will be described later in this report, part of the Eastern Interconnection became unstable on August 14, resulting in a cascading outage over a wide area.) Stability limits, like thermal limits, are expressed as a maximum amount of electricity that can be safely transferred over transmission lines.

   There are two types of stability limits: (1) Voltage stability limits are set to ensure that the unplanned loss of a line or generator (which may have been providing locally critical reactive power support, as described previously) will not cause voltages to fall to dangerously low levels. If voltage falls too low, it begins to collapse uncontrollably, at which point automatic relays either shed load or trip generators to avoid damage. (2) Power (angle) stability limits are set to ensure that a short circuit or an unplanned loss of a line, transformer, or generator will not cause the remaining generators and loads being served to lose synchronism with one another. (Recall that all generators and loads within an interconnection must operate at or very near a common 60 Hz frequency.) Loss of synchronism with the common frequency means generators are operating out-of-step with one another. Even modest losses of synchronism can result in damage to generation equipment. Under extreme losses of synchronism, the grid may break apart into separate electrical islands; each island would begin to maintain its own frequency, determined by the load/generation balance within the island.

5. **Operate the system so that it remains in a reliable condition even if a contingency occurs, such as the loss of a key generator or transmission facility (the "N minus 1 criterion").** The central organizing principle of electricity reliability management is to plan for the unexpected. The unique characteristics of electricity

mean that problems, when they arise, can spread and escalate very quickly if proper safeguards are not in place. Accordingly, through years of experience, the industry has developed a network of defensive strategies for maintaining reliability based on the assumption that equipment can and will fail unexpectedly upon occasion.

This principle is expressed by the requirement that the system must be operated at all times to ensure that it will remain in a secure condition (generally within emergency ratings for current and voltage and within established stability limits) following the loss of the most important generator or transmission facility (a "worst single contingency"). This is called the "N-1 criterion." In other words, because a generator or line trip can occur at any time from random failure, the power system must be operated in a preventive mode so that the loss of the most important generator or transmission facility does not jeopardize the remaining facilities in the system by causing them to exceed their emergency ratings or stability limits, which could lead to a cascading outage.

Further, when a contingency does occur, the operators are required to identify and assess immediately the new worst contingencies, given the changed conditions, and promptly make any adjustments needed to ensure that if one of them were to occur, the system would still remain operational and safe. NERC operating policy requires that the system be restored as soon as practical but within no more than 30 minutes to compliance with normal limits, and to a condition where it can once again withstand the next-worst single contingency without violating thermal, voltage, or stability limits. A few areas of the grid are operated to withstand the concurrent loss of two or more facilities (i.e., "N-2"). This may be done, for example, as an added safety measure to protect

Why Don't More Blackouts Happen?

Given the complexity of the bulk power system and the day-to-day challenges of operating it, there are a lot of things that could go wrong—which makes it reasonable to wonder why so few large outages occur.

Large outages or blackouts are infrequent because responsible system owners and operators practice "defense in depth," meaning that they protect the bulk power system through layers of safety-related practices and equipment. These include:

1. **A range of rigorous planning and operating studies, including long-term assessments, year-ahead, season-ahead, week-ahead, day-ahead, hour-ahead, and real-time operational contingency analyses.** Planners and operators use these to evaluate the condition of the system, anticipate problems ranging from likely to low probability but high consequence, and develop a good understanding of the limits and rules for safe, secure operation under such contingencies. If multiple contingencies occur in a single area, they are likely to be interdependent rather than random, and should have been anticipated in planning studies.
2. **Preparation for the worst case.** The operating rule is to always prepare the system to be safe in the face of the worst single contingency that could occur relative to current conditions, which means that the system is also prepared for less adverse contingencies.
3. **Quick response capability.** Most potential problems first emerge as a small, local situation. When a small, local problem is handled quickly and responsibly using NERC operating practices—particularly to return the system to N-1 readiness within 30 minutes or less—the problem can usually be resolved and contained before it grows beyond local proportions.
4. **Maintain a surplus of generation and transmission.** This provides a cushion in day-to-day operations, and helps ensure that small problems don't become big problems.
5. **Have backup capabilities for all critical functions.** Most owners and operators maintain backup capabilities—such as redundant equipment already on-line (from generation in spinning reserve and transmission operating margin and limits to computers and other operational control systems)—and keep an inventory of spare parts to be able to handle an equipment failure.

a densely populated metropolitan area or when lines share a common structure and could be affected by a common failure mode, e.g., a single lightning strike.

6. **Plan, design, and maintain the system to operate reliably.** Reliable power system operation requires far more than monitoring and controlling the system in real-time. Thorough planning, design, maintenance, and analysis are required to ensure that the system can be operated reliably and within safe limits. Short-term planning addresses day-ahead and week-ahead operations planning; long-term planning focuses on providing adequate generation resources and transmission capacity to ensure that in the future the system will be able to withstand severe contingencies without experiencing widespread, uncontrolled cascading outages.

   A utility that serves retail customers must estimate future loads and, in some cases, arrange for adequate sources of supplies and plan adequate transmission and distribution infrastructure. NERC planning standards identify a range of possible contingencies and set corresponding expectations for system performance under several categories of possible events, ranging from everyday "probable" events to "extreme" events that may involve substantial loss of customer load and generation in a widespread area. NERC planning standards also address requirements for voltage support and reactive power, disturbance monitoring, facility ratings, system modeling and data requirements, system protection and control, and system restoration.

7. **Prepare for emergencies.** System operators are required to take the steps described above to plan and operate a reliable power system, but emergencies can still occur because of external factors such as severe weather, operator error, or equipment failures that exceed planning, design, or operating criteria. For these rare events, the operating entity is required to have emergency procedures covering a credible range of emergency scenarios. Operators must be trained to recognize and take effective action in response to these emergencies. To deal with a system emergency that results in a blackout, such as the one that occurred on August 14, 2003, there must be procedures and capabilities to use "black start" generators (capable of restarting with no external power source) and to coordinate operations in order to restore the system as quickly as possible to a normal and reliable condition.

Reliability Organizations Oversee Grid Reliability in North America

NERC is a non-governmental entity whose mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. The organization was established in 1968, as a result of the Northeast blackout in 1965. Since its inception, NERC has operated as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of all those involved to ensure compliance with reliability requirements. An independent board governs NERC.

To fulfill its mission, NERC:

- Sets standards for the reliable operation and planning of the bulk electric system.
- Monitors and assesses compliance with standards for bulk electric system reliability.
- Provides education and training resources to promote bulk electric system reliability.
- Assesses, analyzes and reports on bulk electric system adequacy and performance.
- Coordinates with regional reliability councils and other organizations.
- Coordinates the provision of applications (tools), data and services necessary to support the reliable operation and planning of the bulk electric system.
- Certifies reliability service organizations and personnel.
- Coordinates critical infrastructure protection of the bulk electric system.
- Enables the reliable operation of the interconnected bulk electric system by facilitating information exchange and coordination among reliability service organizations.

Recent changes in the electricity industry have altered many of the traditional mechanisms, incentives and responsibilities of the entities involved in ensuring reliability, to the point that the voluntary system of compliance with reliability standards is generally recognized as not adequate to current needs.[3] NERC and many other electricity organizations support the development of a new mandatory system of reliability standards and compliance, backstopped in the United States by the Federal Energy Regulatory Commission. This will require federal legislation in the United States to provide for the creation of a new electric reliability organization with the statutory authority to enforce compliance with reliability standards among all market participants. Appropriate government entities in Canada and Mexico are prepared to take similar action, and some have already done so. In the meantime, NERC encourages compliance with its reliability standards through an agreement with its members.

NERC's members are ten regional reliability councils. (See Figure 2.5 for a map showing the locations and boundaries of the regional councils.) In turn, the regional councils have broadened their membership to include all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. Collectively, the members of the NERC regions account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The ten regional councils jointly fund NERC and adapt NERC standards to meet the needs of their regions. The August 14 blackout affected three NERC regional reliability councils—East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Northeast Power Coordinating Council (NPCC).

"Control areas" are the primary operational entities that are subject to NERC and regional council standards for reliability. A control area is a geographic area within which a single entity, Independent System Operator (ISO), or Regional Transmission Organization (RTO) balances generation and loads in real time to maintain reliable operation. Control areas are linked with each other through transmission interconnection tie lines. Control area operators control generation directly to maintain their electricity interchange schedules with other control areas. They also operate collectively to support the reliability of their interconnection. As shown in Figure 2.6, there are approximately 140 control areas in North America. The control area dispatch centers have sophisticated monitoring and control systems and are staffed 24 hours per day, 365 days per year.

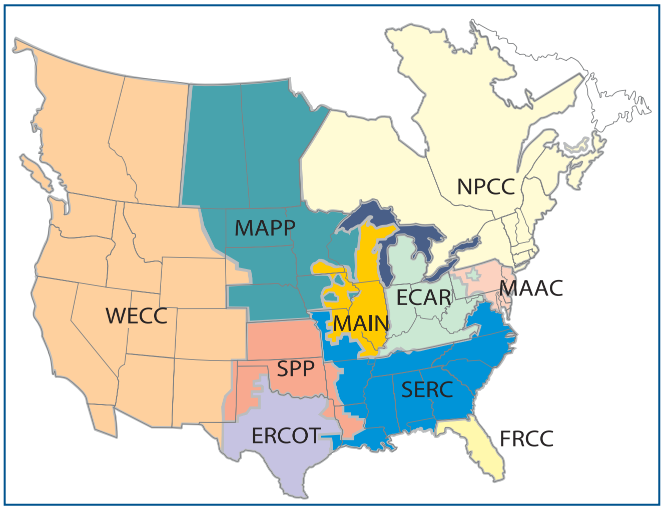
Traditionally, control areas were defined by utility service area boundaries and operations were largely managed by vertically integrated utilities that owned and operated generation, transmission, and distribution. While that is still true in some areas, there has been significant restructuring of operating functions and some consolidation of control areas into regional operating entities. Utility industry restructuring has led to an unbundling of generation, transmission and distribution activities such that the ownership and operation of these assets have been separated either functionally or through the formation of independent entities called Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

- ISOs and RTOs in the United States have been authorized by FERC to implement aspects of the Energy Policy Act of 1992 and subsequent FERC policy directives.
- The primary functions of ISOs and RTOs are to manage in real time and on a day-ahead basis the reliability of the bulk power system and the operation of wholesale electricity markets within their footprint.
- ISOs and RTOs do not own transmission assets; they operate or direct the operation of assets owned by their members.
- ISOs and RTOs may be control areas themselves, or they may encompass more than one control area.
- ISOs and RTOs may also be NERC Reliability Coordinators, as described below.

Five RTOs/ISOs are within the area directly affected by the August 14 blackout. They are:

- Midwest Independent System Operator (MISO)
- PJM Interconnection (PJM)

Figure 2.5. NERC Regions



- ◆ New York Independent System Operator (NYISO)
- ◆ New England Independent System Operator (ISO-NE)
- ◆ Ontario Independent Market Operator (IMO)

Reliability coordinators provide reliability oversight over a wide region. They prepare reliability assessments, provide a wide-area view of reliability, and coordinate emergency operations in real time for one or more control areas. They may operate, but do not participate in, wholesale or retail market functions. There are currently 18 reliability coordinators in North America. Figure 2.7 shows the locations and boundaries of their respective areas.

Key Parties in the Pre-Cascade Phase of the August 14 Blackout

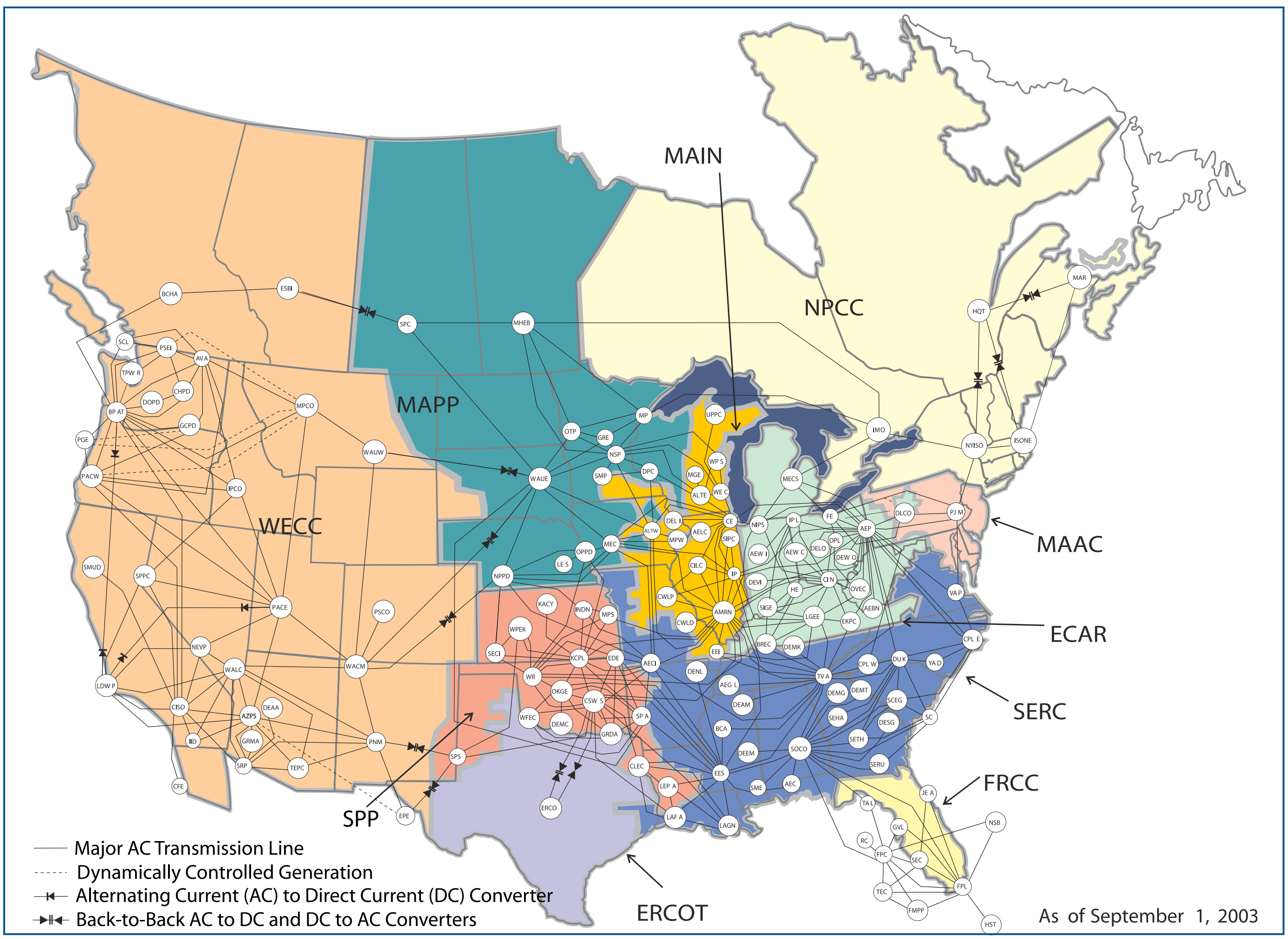
The initiating events of the blackout involved two control areas—FirstEnergy (FE) and American Electric Power (AEP)—and their respective reliability coordinators, MISO and PJM (see Figures 2.7 and 2.8). These organizations and their reliability responsibilities are described briefly in this final subsection.

1. **FirstEnergy operates a control area in northern Ohio.** FirstEnergy (FE) consists of seven electric utility operating companies. Four of these companies, Ohio Edison, Toledo Edison, The Illuminating Company, and Penn Power, operate in the NERC ECAR region, with MISO serving as their reliability coordinator. These four companies now operate as one integrated control area managed by FE.[4]

2. **American Electric Power (AEP) operates a control area in Ohio just south of FE.** AEP is both a transmission operator and a control area operator.

3. **Midwest Independent System Operator (MISO) is the reliability coordinator for FirstEnergy.** The Midwest Independent System

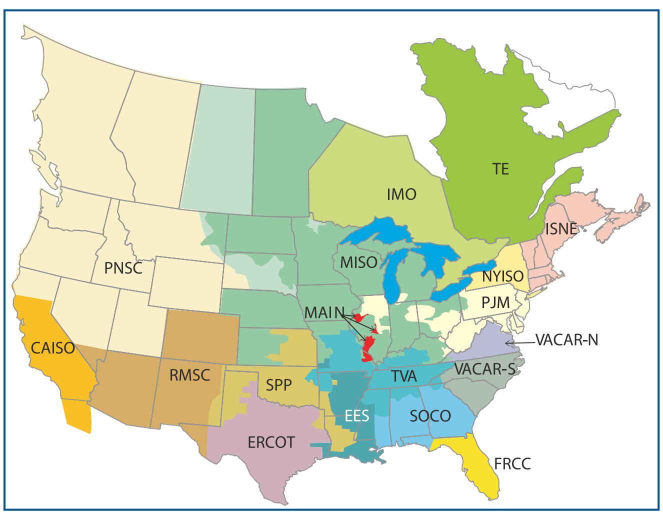
Figure 2.6. NERC Regions and Control Areas



Operator (MISO) is the reliability coordinator for a region of more than 1 million square miles (2.6 million square kilometers), stretching from Manitoba, Canada in the north to Kentucky in the south, from Montana in the west to western Pennsylvania in the east. Reliability coordination is provided by two offices, one in Minnesota, and the other at the MISO headquarters in Indiana. Overall, MISO provides reliability coordination for 37 control areas, most of which are members of MISO.

4. **PJM is AEP's reliability coordinator.** PJM is one of the original ISOs formed after FERC orders 888 and 889, but was established as a regional power pool in 1935. PJM recently expanded its footprint to include control areas and transmission operators within MAIN and ECAR (PJM-West). It performs its duties as a reliability coordinator in different ways, depending on the control areas involved. For PJM-East, it is both the control area and reliability coordinator for ten utilities, whose transmission systems span the Mid-Atlantic region of New Jersey, most of Pennsylvania, Delaware, Maryland, West Virginia, Ohio, Virginia, and the District of Columbia. The PJM-West facility has the reliability coordinator desk for five control areas (AEP, Commonwealth Edison, Duquesne Light, Dayton Power and Light, and Ohio Valley Electric Cooperative) and three generation-only control areas (Duke Energy's Washington County (Ohio) facility, Duke's Lawrence County/Hanging Rock (Ohio) facility, and Allegheny Energy's Buchanan (West Virginia) facility.

Figure 2.7. NERC Reliability Coordinators



Reliability Responsibilities of Control Area Operators and Reliability Coordinators

1. **Control area operators have primary responsibility for reliability.** Their most important responsibilities, in the context of this report, are:

   N-1 criterion. NERC Operating Policy 2.A—Transmission Operations:

   > "All CONTROL AREAS shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency."

   Emergency preparedness and emergency response. NERC Operating Policy 5—Emergency Operations, General Criteria:

   > "Each system and CONTROL AREA shall promptly take appropriate action to relieve any abnormal conditions, which jeopardize reliable Interconnection operation."

   > "Each system, CONTROL AREA, and Region shall establish a program of manual and automatic load shedding which is designed to arrest frequency or voltage decays that could result in an uncontrolled failure of components of the interconnection."

   > NERC Operating Policy 5.A—Coordination with Other Systems:

   > "A system, CONTROL AREA, or pool that is experiencing or anticipating an operating emergency shall communicate its current and future status to neighboring systems, CONTROL AREAS, or pools and throughout the interconnection . . . . A system shall inform

Figure 2.8. Reliability Coordinators and Control Areas in Ohio and Surrounding States

other systems . . . whenever . . . the system's condition is burdening other systems or reducing the reliability of the Interconnection . . . [or whenever] the system's line loadings and voltage/reactive levels are such that a single contingency could threaten the reliability of the Interconnection."

NERC Operating Policy 5.C—Transmission System Relief:

"Action to correct an OPERATING SECURITY LIMIT violation shall not impose unacceptable stress on internal generation or transmission equipment, reduce system reliability beyond acceptable limits, or unduly impose voltage or reactive burdens on neighboring systems. If all other means fail, corrective action may require load reduction."

Operating personnel and training: NERC Operating Policy 8.B—Training:

"Each OPERATING AUTHORITY should periodically practice simulated emergencies. The scenarios included in practice situations should represent a variety of operating conditions and emergencies."

2. **Reliability Coordinators** such as MISO and PJM are expected to comply with all aspects of NERC Operating Policies, especially Policy 9, Reliability Coordinator Procedures, and its appendices. Key requirements include:

NERC Operating Policy 9, Criteria for Reliability Coordinators, 5.2:

Have "detailed monitoring capability of the RELIABILITY AREA and sufficient monitoring

Institutional Complexities and Reliability in the Midwest

The institutional arrangements for reliability in the Midwest are much more complex than they are in the Northeast—i.e., the areas covered by the Northeast Power Coordinating Council (NPCC) and the Mid-Atlantic Area Council (MAAC). There are two principal reasons for this complexity. One is that in NPCC and MAAC, the independent system operator (ISO) also serves as the single control area operator for the individual member systems. In comparison, MISO provides reliability coordination for 35 control areas in the ECAR, MAIN, and MAPP regions and 2 others in the SPP region, and PJM provides reliability coordination for 8 control areas in the ECAR and MAIN regions (plus one in MAAC). (See table below.) This results in 18 control-area-to-control-area interfaces across the PJM/MISO reliability coordinator boundary.

The other is that MISO has less reliability-related authority over its control area members than PJM has over its members. Arguably, this lack of authority makes day-to-day reliability operations more challenging. Note, however, that (1) FERC's authority to require that MISO have greater authority over its members is limited; and (2) before approving MISO, FERC asked NERC for a formal assessment of whether reliability could be maintained under the arrangements proposed by MISO and PJM. After reviewing proposed plans for reliability coordination within and between PJM and MISO, NERC replied affirmatively but provisionally. FERC approved the new MISO-PJM configuration based on NERC's assessment. NERC conducted audits in November and December 2002 of the MISO and PJM reliability plans, and some of the recommendations of the audit teams are still being addressed. The adequacy of the plans and whether the plans were being implemented as written are factors in NERC's ongoing investigation.

Reliability Coordinator (RC)	Control Areas in RC Area	Regional Reliability Councils Affected and Number of Control Areas	Control Areas of Interest in RC Area
MISO	37	ECAR (12), MAIN (9), MAPP (14), SPP (2)	FE, Cinergy, Michigan Electric Coordinated System
PJM	9	MAAC (1), ECAR (7), MAIN (1)	PJM, AEP, Dayton Power & Light
ISO New England	2	NPCC (2)	ISONE, Maritime Provinces
New York ISO	1	NPCC (1)	NYISO
Ontario Independent Market Operator	1	NPCC (1)	IMO
Trans-Energie	1	NPCC (1)	Hydro Québec

capability of the surrounding RELIABILITY AREAS to ensure potential security violations are identified."

NERC Operating Policy 9, Functions of Reliability Coordinators, 1.7:

> "Monitor the parameters that may have significant impacts within the RELIABILITY AREA and with neighboring RELIABILITY AREAS with respect to . . . sharing with other RELIABILITY COORDINATORS any information regarding potential, expected, or actual critical operating conditions that could negatively impact other RELIABILITY AREAS. The RELIABILITY COORDINATOR will coordinate with other RELIABILITY COORDINATORS and CONTROL AREAS as needed to develop appropriate plans to mitigate negative impacts of potential, expected, or actual critical operating conditions . . . ."

What Constitutes an Operating Emergency?

An operating emergency is an unsustainable condition that cannot be resolved using the resources normally available. The NERC Operating Manual defines a "capacity emergency" as when a system's or pool's operating generation capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements. It defines an "energy emergency" as when a load-serving entity has exhausted all other options and can no longer provide its customers' expected energy requirements. A transmission emergency exists when "the system's line loadings and voltage/ reactive levels are such that a single contingency could threaten the reliability of the Interconnection." Control room operators and dispatchers are given substantial latitude to determine when to declare an emergency. (See pages 66-67 in Chapter 5 for more detail.)

NERC Operating Policy 9, Functions of Reliability Coordinators, 6:

> "Conduct security assessment and monitoring programs to assess contingency situations. Assessments shall be made in real time and for the operations planning horizon at the CONTROL AREA level with any identified problems reported to the RELIABILITY COORDINATOR. The RELIABILITY COORDINATOR is to ensure that CONTROL AREA, RELIABILITY AREA, and regional boundaries are sufficiently modeled to capture any problems crossing such boundaries."

Endnotes

1 The province of Québec, although considered a part of the Eastern Interconnection, is connected to the rest of the Eastern Interconnection only by DC ties. In this instance, the DC ties acted as buffers between portions of the Eastern Interconnection; transient disturbances propagate through them less readily. Therefore, the electricity system in Québec was not affected by the outage, except for a small portion of the province's load that is directly connected to Ontario by AC transmission lines. (Although DC ties can act as a buffer between systems, the tradeoff is that they do not allow instantaneous generation support following the unanticipated loss of a generating unit.)

2 In some locations, bulk power flows are controlled through specialized devices or systems, such as phase angle regulators, "flexible AC transmission systems" (FACTS), and high-voltage DC converters (and reconverters) spliced into the AC system. These devices are still too expensive for general application.

3 See, for example, *Maintaining Reliability in a Competitive Electric Industry* (1998), a report to the U.S. Secretary of Energy by the Task Force on Electric Systems Reliability; *National Energy Policy* (2001), a report to the President of the United States by the National Energy Policy Development Group, p. 7-6; and *National Transmission Grid Study* (2002), U.S. Dept. of Energy, pp. 46-48.

4 The remaining three FE companies, Penelec, Met-Ed, and Jersey Central Power & Light, are in the NERC MAAC region and have PJM as their reliability coordinator. The focus of this report is on the portion of FE in the ECAR reliability region and within the MISO reliability coordinator footprint.

3. Causes of the Blackout and Violations of NERC Standards

Summary

This chapter explains in summary form the causes of the initiation of the blackout in Ohio, based on the analyses by the bi-national investigation team. It also lists NERC's findings to date concerning seven specific violations of its reliability policies, guidelines, and standards. Last, it explains how some NERC standards and processes were inadequate because they did not give sufficiently clear direction to industry members concerning some preventive measures needed to maintain reliability, and that NERC does not have the authority to enforce compliance with the standards. Clear standards with mandatory compliance, as contemplated under legislation pending in the U.S. Congress, might have averted the start of this blackout.

Chapters 4 and 5 provide the details that support the conclusions summarized here, by describing conditions and events during the days before and the day of the blackout, and explain how those events and conditions did or did not cause or contribute to the initiation of the blackout. Chapter 6 addresses the cascade as the blackout spread beyond Ohio and reviews the causes and events of the cascade as distinct from the earlier events in Ohio.

The Causes of the Blackout in Ohio

A dictionary definition of "cause" is "something that produces an effect, result, or consequence."[1] In searching for the causes of the blackout, the investigation team looked back through the progression of sequential events, actions and inactions to identify the cause(s) of each event. The idea of "cause" is here linked not just to what happened or why it happened, but more specifically to the entities whose duties and responsibilities were to anticipate and prepare to deal with the things that could go wrong. Four major causes, or groups of causes, are identified (see box on page 18).

Although the causes discussed below produced the failures and events of August 14, they did not leap into being that day. Instead, as the following chapters explain, they reflect long-standing institutional failures and weaknesses that need to be understood and corrected in order to maintain reliability.

Linking Causes to Specific Weaknesses

Seven violations of NERC standards, as identified by NERC,[2] and other conclusions reached by NERC and the bi-national investigation team are aligned below with the specific causes of the blackout. There is an additional category of conclusions beyond the four principal causes—the failure to act, when it was the result of preceding conditions. For instance, FE did not respond to the loss of its transmission lines because it did not have sufficient information or insight to reveal the need for action. Note: NERC's list of violations has been revised and extended since publication of the Interim Report. Two violations (numbers 4 and 6, as cited in the Interim Report) were dropped, and three new violations have been identified in this report (5, 6, and 7, as numbered here). NERC continues to study the record and may identify additional violations.[3]

Group 1: FirstEnergy and ECAR failed to assess and understand the inadequacies of FE's system, particularly with respect to voltage instability and the vulnerability of the Cleveland-Akron area, and FE did not operate its system with appropriate voltage criteria and remedial measures.

- FE did not monitor and manage reactive reserves for various contingency conditions as required by NERC Policy 2, Section B, Requirement 2.
- NERC Policy 2, Section A, requires a 30-minute period of time to re-adjust the system to prepare to withstand the next contingency.

Causes of the Blackout's Initiation

The Ohio phase of the August 14, 2003, blackout was caused by deficiencies in specific practices, equipment, and human decisions by various organizations that affected conditions and outcomes that afternoon—for example, insufficient reactive power was an issue in the blackout, but it was not a cause in itself. Rather, deficiencies in corporate policies, lack of adherence to industry policies, and inadequate management of reactive power and voltage caused the blackout, rather than the lack of reactive power. There are four groups of causes for the blackout:

Group 1: FirstEnergy and ECAR failed to assess and understand the inadequacies of FE's system, particularly with respect to voltage instability and the vulnerability of the Cleveland-Akron area, and FE did not operate its system with appropriate voltage criteria. *(Note: This cause was not identified in the Task Force's Interim Report. It is based on analysis completed by the investigative team after the publication of the Interim Report.)*

As detailed in Chapter 4:

A) FE failed to conduct rigorous long-term planning studies of its system, and neglected to conduct appropriate multiple contingency or extreme condition assessments. (See pages 37-39 and 41-43.)

B) FE did not conduct sufficient voltage analyses for its Ohio control area and used operational voltage criteria that did not reflect actual voltage stability conditions and needs. (See pages 31-37.)

C) ECAR (FE's reliability council) did not conduct an independent review or analysis of FE's voltage criteria and operating needs, thereby allowing FE to use inadequate practices without correction. (See page 39.)

D) Some of NERC's planning and operational requirements and standards were sufficiently ambiguous that FE could interpret them to include practices that were inadequate for reliable system operation. (See pages 31-33.)

Group 2: Inadequate situational awareness at FirstEnergy. FE did not recognize or understand the deteriorating condition of its system.

As discussed in Chapter 5:

A) FE failed to ensure the security of its transmission system after significant unforeseen contingencies because it did not use an effective contingency analysis capability on a routine basis. (See pages 49-50 and 64.)

B) FE lacked procedures to ensure that its operators were continually aware of the functional state of their critical monitoring tools. (See pages 51-53, 56.)

C) FE control center computer support staff and operations staff did not have effective internal communications procedures. (See pages 54, 56, and 65-67.)

D) FE lacked procedures to test effectively the functional state of its monitoring tools after repairs were made. (See page 54.)

E) FE did not have additional or back-up monitoring tools to understand or visualize the status of their transmission system to facilitate its operators' understanding of transmission system conditions after the failure of their primary monitoring/alarming systems. (See pages 53, 56, and 65.)

Group 3: FE failed to manage adequately tree growth in its transmission rights-of-way.

This failure was the common cause of the outage of three FE 345-kV transmission lines and one 138-kV line. (See pages 57-64.)

Group 4: Failure of the interconnected grid's reliability organizations to provide effective real-time diagnostic support.

As discussed in Chapter 5:

A) MISO did not have real-time data from Dayton Power and Light's Stuart-Atlanta 345-kV line incorporated into its state estimator (a system monitoring tool). This precluded

(continued on page 19)

Causes of the Blackout's Initiation (Continued)

MISO from becoming aware of FE's system problems earlier and providing diagnostic assistance or direction to FE. (See pages 49-50.)

B) MISO's reliability coordinators were using non-real-time data to support real-time "flowgate" monitoring. This prevented MISO from detecting an N-1 security violation in FE's system and from assisting FE in necessary relief actions. (See pages 48 and 63.)

C) MISO lacked an effective way to identify the location and significance of transmission line breaker operations reported by their Energy Management System (EMS). Such information would have enabled MISO operators to become aware earlier of important line outages. (See page 48.)

D) PJM and MISO lacked joint procedures or guidelines on when and how to coordinate a security limit violation observed by one of them in the other's area due to a contingency near their common boundary. (See pages 62-63 and 65-66.)

In the chapters that follow, sections that relate to particular causes are denoted with the following symbols:

Cause 1 Inadequate System Understanding

Cause 2 Inadequate Situational Awareness

Cause 3 Inadequate Tree Trimming

Cause 4 Inadequate RC Diagnostic Support

- NERC is lacking a well-defined control area (CA) audit process that addresses all CA responsibilities. Control area audits have generally not been conducted with sufficient regularity and have not included a comprehensive audit of the control area's compliance with all NERC and Regional Council requirements. Compliance with audit results is not mandatory.
- ECAR did not conduct adequate review or analyses of FE's voltage criteria, reactive power management practices, and operating needs.
- FE does not have an adequate automatic undervoltage load-shedding program in the Cleveland-Akron area.

Group 2: Inadequate situational awareness at FirstEnergy. FE did not recognize or understand the deteriorating condition of its system.

Violations (Identified by NERC):

- **Violation 7:** FE's operational monitoring equipment was not adequate to alert FE's operators regarding important deviations in operating conditions and the need for corrective action as required by NERC Policy 4, Section A, Requirement 5.
- **Violation 3:** FE's state estimation and contingency analysis tools were not used to assess system conditions, violating NERC Operating Policy 5, Section C, Requirement 3, and Policy 4, Section A, Requirement 5.

Other Problems:

- FE personnel did not ensure that their Real-Time Contingency Analysis (RTCA) was a functional and effective EMS application as required by NERC Policy 2, Section A, Requirement 1.
- FE's operational monitoring equipment was not adequate to provide a means for its operators to evaluate the effects of the loss of significant transmission or generation facilities as required by NERC Policy 4, Section A, Requirement 4.
- FE's operations personnel were not provided sufficient operations information and analysis tools as required by NERC Policy 5, Section C, Requirement 3.
- FE's operations personnel were not adequately trained to maintain reliable operation under emergency conditions as required by NERC Policy 8, Section 1.
- NERC Policy 4 has no detailed requirements for: (a) monitoring and functional testing of critical EMS and supervisory control and data acquisition (SCADA) systems, and (b) contingency analysis.
- NERC Policy 6 includes a requirement to plan for loss of the primary control center, but lacks specific provisions concerning what must be addressed in the plan.
- NERC system operator certification tests for basic operational and policy knowledge.

Significant additional training is needed to qualify an individual to perform system operation and management functions.

Group 3: FE failed to manage adequately tree growth in its transmission rights-of-way. This failure was the common cause of the outage of three FE 345-kV transmission lines and affected several 138-kV lines.

- FE failed to maintain equipment ratings through a vegetation management program. A vegetation management program is necessary to fulfill NERC Policy 2, Section A, Requirement 1 (Control areas shall develop, maintain, and implement formal policies and procedures to provide for transmission security . . . including equipment ratings.)
- Vegetation management requirements are not defined in NERC Standards and Policies.

Group 4: Failure of the interconnected grid's reliability organizations to provide effective diagnostic support.

Violations (Identified by NERC):

- **Violation 4**: MISO did not notify other reliability coordinators of potential system problems as required by NERC Policy 9, Section C, Requirement 2.
- **Violation 5**: MISO was using non-real-time data to support real-time operations, in violation of NERC Policy 9, Appendix D, Section A, Criteria 5.2.
- **Violation 6**: PJM and MISO as reliability coordinators lacked procedures or guidelines between their respective organizations regarding the coordination of actions to address an operating security limit violation observed by one of them in the other's area due to a contingency near their common boundary, as required by Policy 9, Appendix C. **Note**: Policy 9 lacks specifics on what constitutes coordinated procedures and training.

Other Problems:

- MISO did not have adequate monitoring capability to fulfill its reliability coordinator responsibilities as required by NERC Policy 9, Appendix D, Section A.
- Although MISO is the reliability coordinator for FE, on August 14 FE was not a signatory to the MISO Transmission Owners Agreement and was not under the MISO tariff, so MISO did not have the necessary authority as FE's Reliability Coordinator as required by NERC Policy 9, Section B, Requirement 2.
- Although lacking authority under a signed agreement, MISO as reliability coordinator nevertheless should have issued directives to FE to return system operation to a safe and reliable level as required by NERC Policy 9, Section B, Requirement 2, before the cascading outages occurred.
- American Electric Power (AEP) and PJM attempted to use the transmission loading relief (TLR) process to address transmission power flows without recognizing that a TLR would not solve the problem.
- NERC Policy 9 does not contain a requirement for reliability coordinators equivalent to the NERC Policy 2 statement that monitoring equipment is to be used in a manner that would bring to the reliability coordinator's attention any important deviations in operating conditions.
- NERC Policy 9 lacks criteria for determining the critical facilities lists in each reliability coordinator area.
- NERC Policy 9 lacks specifics on coordinated procedures and training for reliability coordinators regarding "operating to the most conservative limit" in situations when operating conditions are not fully understood.

Failures to act by FirstEnergy or others to solve the growing problem, due to the other causes.

Violations (Identified by NERC):

- **Violation 1:** Following the outage of the Chamberlin-Harding 345-kV line, FE operating personnel did not take the necessary action to return the system to a safe operating state as required by NERC Policy 2, Section A, Standard 1.
- **Violation 2:** FE operations personnel did not adequately communicate its emergency operating conditions to neighboring systems as required by NERC Policy 5, Section A.

Other Problems:

- FE operations personnel did not promptly take action as required by NERC Policy 5, General

Criteria, to relieve the abnormal conditions resulting from the outage of the Harding-Chamberlin 345-kV line.

- FE operations personnel did not implement measures to return system operation to within security limits in the prescribed time frame of NERC Policy 2, Section A, Standard 2, following the outage of the Harding-Chamberlin 345-kV line.
- FE operations personnel did not exercise the authority to alleviate the operating security limit violation as required by NERC Policy 5, Section C, Requirement 2.
- FE did not exercise a load reduction program to relieve the critical system operating conditions as required by NERC Policy 2, Section A, Requirement 1.2.
- FE did not demonstrate the application of effective emergency operating procedures as required by NERC Policy 6, Section B, Emergency Operations Criteria.
- FE operations personnel did not demonstrate that FE has an effective manual load shedding program designed to address voltage decays that result in uncontrolled failure of components of the interconnection as required by NERC Policy 5, General Criteria.
- NERC Policy 5 lacks specifics for Control Areas on procedures for coordinating with other systems and training regarding "operating to the most conservative limit" in situations when operating conditions are not fully understood.

Institutional Issues

As indicated above, the investigation team identified a number of institutional issues with respect to NERC's reliability standards. Many of the institutional problems arise not because NERC is an inadequate or ineffective organization, but rather because it has no structural independence from the industry it represents and has no authority to develop strong reliability standards and to enforce compliance with those standards. While many in the industry and at NERC support such measures, legislative action by the U.S. Congress is needed to make this happen.

These institutional issues can be summed up generally:

1. Although NERC's provisions address many of the factors and practices which contributed to the blackout, some of the policies or guidelines are inexact, non-specific, or lacking in detail, allowing divergent interpretations among reliability councils, control areas, and reliability coordinators. NERC standards are minimum requirements that may be made more stringent if appropriate by regional or subregional bodies, but the regions have varied in their willingness to implement exacting reliability standards.
2. NERC and the industry's reliability community were aware of the lack of specificity and detail in some standards, including definitions of Operating Security Limits, definition of planned outages, and delegation of Reliability Coordinator functions to control areas, but they moved slowly to address these problems effectively.
3. Some standards relating to the blackout's causes lack specificity and measurable compliance criteria, including those pertaining to operator training, back-up control facilities, procedures to operate when part or all of the EMS fails, emergency procedure training, system restoration plans, reactive reserve requirements, line ratings, and vegetation management.
4. The NERC compliance program and region-based auditing process has not been comprehensive or aggressive enough to assess the capability of all control areas to direct the operation of their portions of the bulk power system. The effectiveness and thoroughness of regional councils' efforts to audit for compliance with reliability requirements have varied significantly from region to region. Equally important, absent mandatory compliance and penalty authority, there is no requirement that an entity found to be deficient in an audit must remedy the deficiency.
5. NERC standards are frequently administrative and technical rather than results-oriented.
6. A recently-adopted NERC process for development of standards is lengthy and not yet fully understood or applied by many industry participants. Whether this process can be adapted to support an expedited development of clear and auditable standards for key topics remains to be seen.

7. NERC has not had an effective process to ensure that recommendations made in various reports and disturbance analyses are tracked for accountability. On their own initiative, some regional councils have developed effective tracking procedures for their geographic areas.

Control areas and reliability coordinators operate the grid every day under guidelines, policies, and requirements established by the industry's reliability community under NERC's coordination. If those policies are strong, clear, and unambiguous, then everyone will plan and operate the system at a high level of performance and reliability will be high. But if those policies are ambiguous and do not make entities' roles and responsibilities clear and certain, they allow companies to perform at varying levels and system reliability is likely to be compromised.

Given that NERC has been a voluntary organization that makes decisions based on member votes, if NERC's standards have been unclear, non-specific, lacking in scope, or insufficiently strict, that reflects at least as much on the industry community that drafts and votes on the standards as it does on NERC. Similarly, NERC's ability to obtain compliance with its requirements through its audit process has been limited by the extent to which the industry has been willing to support the audit program.

Endnotes

[1] *Webster's II New Riverside University Dictionary*, Riverside Publishing Co., 1984.

[2] A NERC team looked at whether and how violations of NERC's reliability requirements may have occurred in the events leading up to the blackout. They also looked at whether deficiencies in the requirements, practices and procedures of NERC and the regional reliability organizations may have contributed to the blackout. They found seven specific violations of NERC operating policies (although some are qualified by a lack of specificity in the NERC requirements).

The Standards, Procedures and Compliance Investigation Team reviewed the NERC Policies for violations, building on work and going beyond work done by the Root Cause Analysis Team. Based on that review the Standards team identified a number of violations related to policies 2, 4, 5, and 9.

Violation 1: Following the outage of the Chamberlin-Harding 345-kV line, FE did not take the necessary actions to return the system to a safe operating state within 30 minutes. (While Policy 5 on Emergency Operations does not address the issue of "operating to the most conservative limit" when coordinating with other systems and operating conditions are not understood, other NERC policies do address this matter: Policy 2, Section A, Standard 1, on basic reliability for single contingencies; Policy 2, Section A, Standard 2, to return a system to within operating security limits within 30 minutes; Policy 2, Section A, Requirement 1, for formal policies and procedures to provide for transmission security; Policy 5, General Criteria, to relieve any abnormal conditions that jeopardize reliable operation; Policy 5, Section C, Requirement 1, to relieve security limit violations; and Policy 5, Section 2, Requirement 2, which gives system operators responsibility and authority to alleviate operating security limit violations using timely and appropriate actions.)

Violation 2: FE did not notify other systems of an impending system emergency. (Policy 5, Section A, Requirement 1, directs a system to inform other systems if it is burdening others, reducing system reliability, or if its lack of single contingency coverage could threaten Interconnection reliability. Policy 5, Section A, Criteria, has similar provisions.)

Violation 3: FE's state estimation/contingency analysis tools were not used to assess the system conditions. (This is addressed in Operating Policy 5, Section C, Requirement 3, concerning assessment of Operating Security Limit violations, and Policy 4, Section A, Requirement 5, which addresses using monitoring equipment to inform the system operator of important conditions and the potential need for corrective action.)

Violation 4: MISO did not notify other reliability coordinators of potential problems. (Policy 9, Section C, Requirement 2, directing the reliability coordinator to alert all control areas and reliability coordinators of a potential transmission problem.)

Violation 5: MISO was using non-real-time data to support real-time operations. (Policy 9, Appendix D, Section A, Criteria For Reliability Coordinators 5.2, regarding adequate facilities to perform their responsibilities, including detailed monitoring capability to identify potential security violations.)

Violation 6: PJM and MISO as Reliability Coordinators lacked procedures or guidelines between themselves on when and how to coordinate an operating security limit violation observed by one of them in the other's area due to a contingency near their common boundary (Policy 9, Appendix 9C, Emergency Procedures). **Note**: Since Policy 9 lacks specifics on coordinated procedures and training, it was not possible for the bi-national team to identify the exact violation that occurred.

Violation 7: The monitoring equipment provided to FE operators was not sufficient to bring the operators' attention to the deviation on the system. (Policy 4, Section A, System Monitoring Requirements regarding resource availability and the use of monitoring equipment to alert operators to the need for corrective action.)

[3] NERC has not yet completed its review of planning standards and violations.

4. Context and Preconditions for the Blackout: The Northeastern Power Grid Before the Blackout Began

Summary

This chapter reviews the state of the northeast portion of the Eastern Interconnection during the days and hours before 16:00 EDT on August 14, 2003, to determine whether grid conditions before the blackout were in some way unusual and might have contributed to the initiation of the blackout. Task Force investigators found that at 15:05 Eastern Daylight Time, immediately before the tripping (automatic shutdown) of FirstEnergy's (FE) Harding-Chamberlin 345-kV transmission line, the system was electrically secure and was able to withstand the occurrence of any one of more than 800 contingencies, including the loss of the Harding-Chamberlin line. At that time the system was electrically within prescribed limits and in compliance with NERC's operating policies.

Determining that the system was in a reliable operational state at 15:05 EDT on August 14, 2003, is extremely significant for determining the causes of the blackout. It means that none of the electrical conditions on the system before 15:05 EDT was a direct cause of the blackout. This eliminates a number of possible causes of the blackout, whether individually or in combination with one another, such as:

- Unavailability of individual generators or transmission lines
- High power flows across the region
- Low voltages earlier in the day or on prior days
- System frequency variations
- Low reactive power output from independent power producers (IPPs).

This chapter documents that although the system was electrically secure, there was clear experience and evidence that the Cleveland-Akron area was highly vulnerable to voltage instability problems. While it was possible to operate the system securely despite those vulnerabilities, FirstEnergy was not doing so because the company had not conducted the long-term and operational planning studies needed to understand those vulnerabilities and their operational implications.

It is important to emphasize that establishing whether conditions were normal or unusual prior to and on August 14 does not change the responsibilities and actions expected of the organizations and operators charged with ensuring power system reliability. As described in Chapter 2, the electricity industry has developed and codified a set of mutually reinforcing reliability standards and practices to ensure that system operators are prepared for the unexpected. The basic assumption underlying these standards and practices is that power system elements will fail or become unavailable in unpredictable ways and at

Reliability and Security

NERC—and this report—use the following definitions for reliability, adequacy, and security.

Reliability: The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electricity supply.

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security: The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

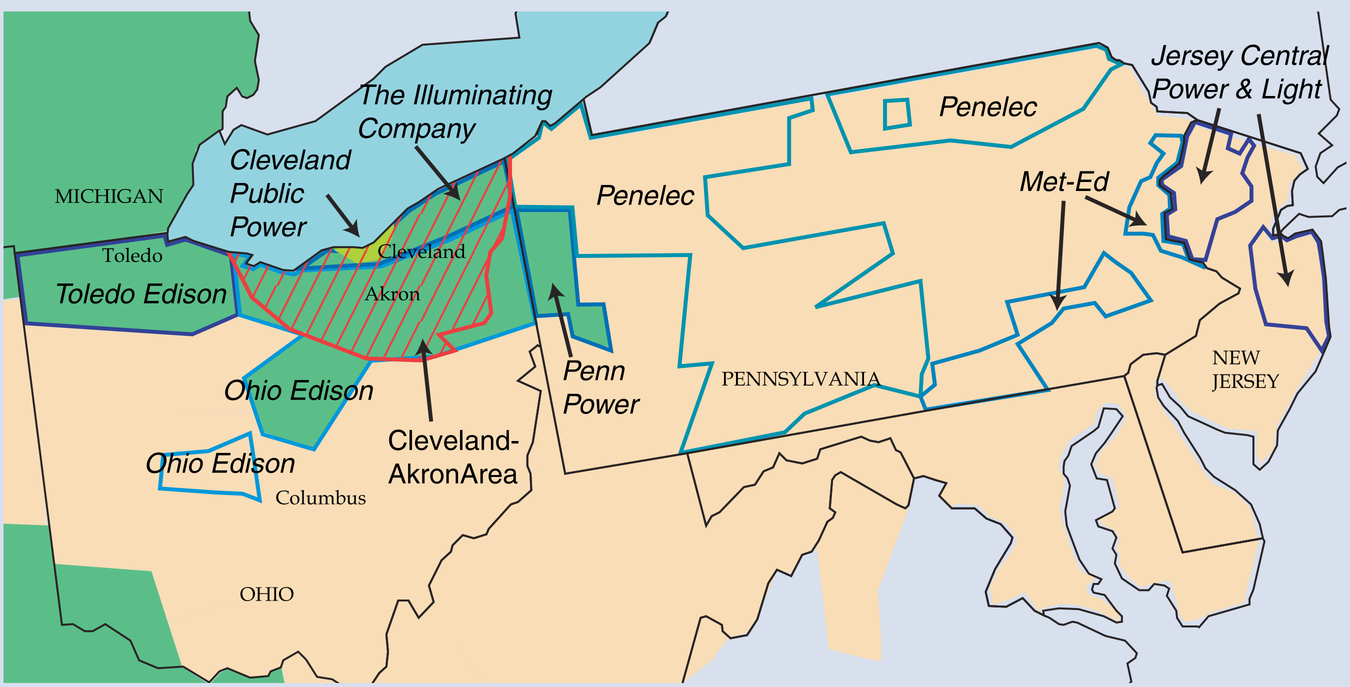
unpredictable times. Sound reliability management is designed to ensure that operators can continue to operate the system within appropriate thermal, voltage, and stability limits following the unexpected loss of any key element (such as a major generator or key transmission facility). These practices have been designed to maintain a functional and reliable grid, regardless of whether actual operating conditions are normal.

It is a basic principle of reliability management that "operators must operate the system they have in front of them"—unconditionally. The system must be operated at all times to withstand any single contingency and yet be ready within 30 minutes for the next contingency. If a facility is lost unexpectedly, the system operators must determine whether to make operational changes, including adjusting generator outputs, curtailing

Geography Lesson

In analyzing the August 14 blackout, it is crucial to understand the geography of the FirstEnergy area. FirstEnergy has seven subsidiary distribution utilities: Toledo Edison, Ohio Edison, and The Illuminating Company in Ohio and four more in Pennsylvania and New Jersey. Its Ohio control area spans the three Ohio distribution utility footprints and that of Cleveland Public Power, a municipal utility serving the city of Cleveland. Within FE's Ohio control area is the Cleveland-Akron area, shown in red cross-hatch.

This geographic distinction matters because the Cleveland-Akron area is a transmission-constrained load pocket with relatively limited generation. While some analyses of the blackout refer to voltages and other indicators measured at the boundaries of FE's Ohio control area, those indicators have limited relevance to the blackout—the indicators of conditions at the edges of and within the Cleveland-Akron area are the ones that matter.



Area	All-Time Peak Load (MW)	Load on August 14, 2003 (MW)
Cleveland-Akron Area (including Cleveland Public Power)	7,340	6,715
FirstEnergy Control Area, Ohio	13,299	12,165
FirstEnergy Retail Area, including PJM	24,267	22,631

NA = not applicable.

electricity transactions, taking transmission elements out of service or restoring them, and if necessary, shedding interruptible and firm customer load—i.e., cutting some customers off temporarily, and in the right locations, to reduce electricity demand to a level that matches what the system is then able to deliver safely.

This chapter discusses system conditions in and around northeast Ohio on August 14 and their relevance to the blackout. It reviews electric loads (real and reactive), system topology (transmission and generation equipment availability and capabilities), power flows, voltage profiles and reactive power reserves. The discussion examines actual system data, investigation team modeling results, and past FE and AEP experiences in the Cleveland-Akron area. The detailed analyses will be presented in a NERC technical report.

Electric Demands on August 14

Temperatures on August 14 were hot but in a normal range throughout the northeast region of the United States and in eastern Canada (Figure 4.1). Electricity demands were high due to high air conditioning loads typical of warm days in August, though not unusually so. As the temperature increased from 78°F (26°C) on August 11 to 87°F (31°C) on August 14, peak load within FirstEnergy's control area increased by 20%, from 10,095 MW to 12,165 MW. System operators had successfully managed higher demands in northeast Ohio and across the Midwest, both earlier in the summer and in previous years—historic peak load for FE's control area was 13,299 MW. August 14 was FE's peak demand day in 2003.

Several large operators in the Midwest consistently under-forecasted load levels between August 11 and 14. Figure 4.2 shows forecast and actual power demands for AEP, Michigan Electrical Coordinated Systems (MECS), and FE from August 11 through August 14. Variances between actual and forecast loads are not unusual, but because those forecasts are used for day-ahead planning for generation, purchases, and reactive power management, they can affect equipment availability and schedules for the following day.

The existence of high air conditioning loads across the Midwest on August 14 is relevant because air conditioning loads (like other induction motors) have lower power factors than other customer electricity uses, and consume more reactive power. Because it had been hot for several days in the Cleveland-Akron area, more air conditioners were running to overcome the persistent heat, and consuming relatively high levels of reactive power—further straining the area's limited reactive generation capabilities.

Generation Facilities Unavailable on August 14

Several key generators in the region were out of service going into the day of August 14. On any given day, some generation and transmission capacity is unavailable; some facilities are out for routine maintenance, and others have been forced out by an unanticipated breakdown and require repairs. August 14, 2003, in northeast Ohio was no exception (Table 4.1).

The generating units that were not available on August 14 provide real and reactive power directly to the Cleveland, Toledo, and Detroit areas. Under standard practice, system operators take into account the unavailability of such units and any

Figure 4.1. August 2003 Temperatures in the U.S. Northeast and Eastern Canada

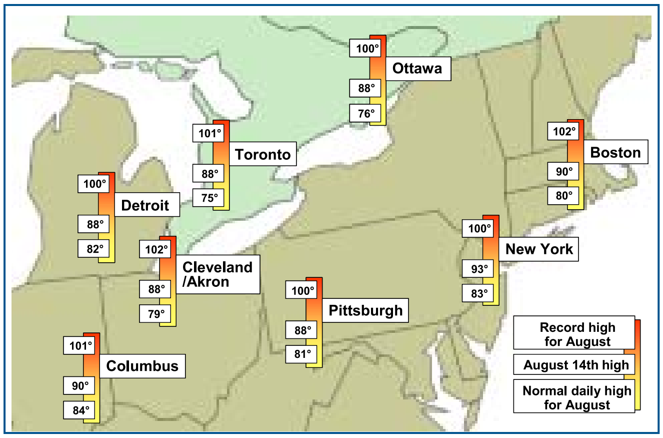
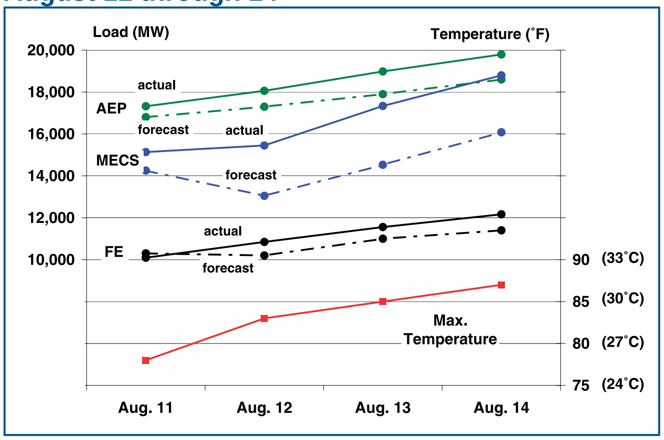


Figure 4.2. Load Forecasts Below Actuals, August 11 through 14



transmission facilities known to be out of service in the day-ahead planning studies they perform to ensure a secure system for the next day. Knowing the status of key facilities also helps operators determine in advance the safe electricity transfer levels for the coming day.

MISO's day-ahead planning studies for August 14 took the above generator outages and transmission outages reported to MISO into account and determined that the regional system could be operated safely. The unavailability of these generation units did not cause the blackout.

On August 14 four or five capacitor banks within the Cleveland-Akron area had been removed from service for routine inspection, including capacitor banks at Fox and Avon 138-kV substations.[1] These static reactive power sources are important for voltage support, but were not restored to

Table 4.1. Generators Not Available on August 14

Generator	Rating	Reason
Davis-Besse Nuclear Unit	883 MW	Prolonged NRC-ordered outage beginning on 3/22/02
Sammis Unit 3	180 MW	Forced outage on 8/12/03
Eastlake Unit 4	238 MW	Forced outage on 8/13/03
Monroe Unit 1	817 MW	Planned outage, taken out of service on 8/8/03
Cook Nuclear Unit 2	1,060 MW	Outage began on 8/13/03

Load Power Factors and Reactive Power

Load power factor is a measure of the relative magnitudes of real power and reactive power consumed by the load connected to a power system. Resistive load, such as electric space heaters or incandescent lights, consumes only real power and no reactive power and has a load power factor of 1.0. Induction motors, which are widely used in manufacturing processes, mining, and homes (e.g., air-conditioners, fan motors in forced-air furnaces, and washing machines) consume both real power and reactive power. Their load power factors are typically in the range of 0.7 to 0.9 during steady-state operation. Single-phase small induction motors (e.g., household items) generally have load power factors in the lower range.

The lower the load power factor, the more reactive power is consumed by the load. For example, a 100 MW load with a load power factor of 0.92 consumes 43 MVAr of reactive power, while the same 100 MW of load with a load power factor of 0.88 consumes 54 MVAr of reactive power. Under depressed voltage conditions, the induction motors used in air-conditioning units and refrigerators, which are used more heavily on hot and humid days, draw even more reactive power than under normal voltage conditions.

In addition to end-user loads, transmission elements such as transformers and transmission lines consume reactive power. Reactive power compensation is required at various locations in the network to support the transmission of real power. Reactive power is consumed within transmission lines in proportion to the square of the electric current shipped, so a 10% increase of power transfer will require a 21% increase in reactive power generation to support the power transfer.

In metropolitan areas with summer peaking loads, it is generally recognized that as temperatures and humidity increase, load demand increases significantly. The power factor impact can be quite large—for example, for a metropolitan area of 5 million people, the shift from winter peak to summer peak demand can shift peak load from 9,200 MW in winter to 10,000 MW in summer; that change to summer electric loads can shift the load power factor from 0.92 in winter down to 0.88 in summer; and this will increase the MVAr load demand from 3,950 in winter up to 5,400 in summer—all due to the changed composition of end uses and the load factor influences noted above.

Reactive power does not travel far, especially under heavy load conditions, and so must be generated close to its point of consumption. This is why urban load centers with summer peaking loads are generally more susceptible to voltage instability than those with winter peaking loads. Thus, control areas must continually monitor and evaluate system conditions, examining reactive reserves and voltages, and adjust the system as necessary for secure operation.

service that afternoon despite the system operators' need for more reactive power in the area.[2] Normal utility practice is to inspect and maintain reactive resources in off-peak seasons so the facilities will be fully available to meet peak loads.

Cause 1
Inadequate System Understanding

The unavailability of the critical reactive resources was not known to those outside of FirstEnergy. NERC policy requires that critical facilities be identified and that neighboring control areas and reliability coordinators be made aware of the status of those facilities to identify the impact of those conditions on their own facilities. However, FE never identified these capacitor banks as critical and so did not pass on status information to others.

Recommendations
23, page 160; 30, page 163

Unanticipated Outages of Transmission and Generation on August 14

Three notable unplanned outages occurred in Ohio and Indiana on August 14 before 15:05 EDT. Around noon, several Cinergy transmission lines in south-central Indiana tripped; at 13:31 EDT, FE's Eastlake 5 generating unit along the southwestern shore of Lake Erie tripped; at 14:02 EDT, a line within the Dayton Power and Light (DPL) control area, the Stuart-Atlanta 345-kV line in southern Ohio, tripped. Only the Eastlake 5 trip was electrically significant to the FirstEnergy system.

- Transmission lines on the Cinergy 345-, 230-, and 138-kV systems experienced a series of outages starting at 12:08 EDT and remained out of service during the entire blackout. The loss of these lines caused significant voltage and loading problems in the Cinergy area. Cinergy made generation changes, and MISO operators responded by implementing transmission loading relief (TLR) procedures to control flows on the transmission system in south-central Indiana. System modeling by the investigation team (see details below, pages 41-43) showed that the loss of these lines was not electrically related to subsequent events in northern Ohio that led to the blackout.
- The Stuart-Atlanta 345-kV line, operated by DPL, and monitored by the PJM reliability coordinator, tripped at 14:02 EDT. This was the result of a tree contact, and the line remained out of service the entire afternoon. As explained below, system modeling by the investigation team has shown that this outage did not cause the subsequent events in northern Ohio that led to the blackout. However, since the line was not in MISO's footprint, MISO operators did not monitor the status of this line and did not know it had gone out of service. This led to a data mismatch that prevented MISO's state estimator (a key monitoring tool) from producing usable results later in the day at a time when system conditions in FE's control area were deteriorating (see details below, pages 46 and 48-49).

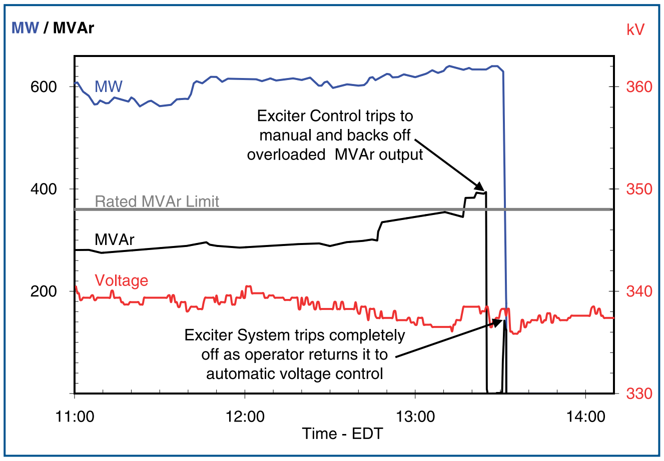
Recommendation
30, page 163

- Eastlake Unit 5 is a 597 MW (net) generating unit located west of Cleveland on Lake Erie. It is a major source of reactive power support for the Cleveland area. It tripped at 13:31 EDT. The cause of the trip was that as the Eastlake 5 operator sought to increase the unit's reactive power output (Figure 4.3), the unit's protection system detected that VAr output exceeded the unit's VAr capability and tripped the unit off-line. The loss of the Eastlake 5 unit did not put the grid into an unreliable state—i.e., it was still able to withstand safely another contingency. However, the loss of the unit required FE to import additional power to make up for the loss of the unit's output (612 MW), made voltage management in northern Ohio more challenging, and gave FE operators less flexibility in operating their system (see details on pages 45-46 and 49-50).

Key Parameters for the Cleveland-Akron Area at 15:05 EDT

The investigation team benchmarked their power flow models against measured data provided by

Figure 4.3. MW and MVAr Output from Eastlake Unit 5 on August 14



FirstEnergy for the Cleveland-Akron area at 15:05 EDT (just before the first of FirstEnergy's key transmission lines failed), as shown in Table 4.2. Although the modeled figures do not match actual system conditions perfectly, overall this model shows a very high correspondence to the actual occurrences and thus its results merit a high degree of confidence. Although Table 4.2 shows only a few key lines within the Cleveland-Akron area, the model was successfully benchmarked to match actual flows, line-by-line, very closely across the entire area for the afternoon of August 14, 2003.

The power flow model assumes the following system conditions for the Cleveland-Akron area at 15:05 EDT on August 14:

- Cleveland-Akron area load = 6,715 MW and 2,402 MVAr
- Transmission losses = 189 MW and 2,514 MVAr
- Reactive power from fixed shunt capacitors (all voltage levels) = 2,585 MVAr
- Reactive power from line charging (all voltage levels) = 739 MVAr
- Network configuration = after the loss of Eastlake 5, before the loss of Harding-Chamberlin 345-kV line
- Area generation combined output: 3,000 MW and 1,200 MVAr.

Cause 1
Inadequate System Understanding

Given these conditions, the power flow model indicates that about 3,900 MW and 400 MVAr of real power and reactive power flow into the Cleveland-Akron area was needed to meet the sum of customer load demanded plus line losses. There was about 688 MVAr of reactive reserve from generation in the area, which is slightly more than the 660 MVAr reactive capability of the Perry nuclear unit. Combined with the fact that a 5% reduction in operating voltage would cause a 10% reduction in reactive power (330 MVAr) from shunt capacitors and line charging and a 10% increase (250 MVAr) in reactive losses from transmission lines, these parameters indicate that the Cleveland-Akron area would be precariously short of reactive power if the Perry plant were lost.

Power Flow Patterns

Several commentators have suggested that the voltage problems in northeast Ohio and the subsequent blackout occurred due to unprecedented high levels of inter-regional power transfers occurring on August 14. Investigation team analysis indicates that in fact, power transfer levels were high but were within established limits and previously experienced levels. Analysis of actual and test case power flows demonstrates that inter-regional power transfers had a minimal effect on the transmission corridor containing the Harding-Chamberlin, Hanna-Juniper, and Star-South Canton 345-kV lines on August 14. It was the increasing native load relative to the limited amount of reactive power available in the Cleveland-Akron area that caused the depletion of reactive power reserves and declining voltages.

On August 14, the flow of power through the ECAR region as a whole (lower Michigan, Indiana, Ohio, Kentucky, West Virginia, and western Pennsylvania) was heavy as a result of transfers of power from the south (Tennessee, etc.) and west (Wisconsin, Minnesota, Illinois, Missouri, etc.) to the north (Ohio, Michigan, and Ontario) and east (New York, Pennsylvania). The destinations for much of the power were northern Ohio, Michigan, PJM, and Ontario. This is shown in Figure 4.4, which shows the flows between control areas on August 14 based on power flow simulations just before the Harding-Chamberlin line tripped at 15:05 EDT. FE's total load peaked at 12,165MW at 16:00 EDT. Actual system data indicate that between 15:00 and 16:00 EDT, actual line flows into FE's control area were 2,695 MW for both transactions and native load.

Table 4.2. Benchmarking Model Results to Actual

FE Circuit		MVA Comparison		
From	To	Model Base Case MVA	Actual 8/14 MVA	Benchmark Accuracy
Chamberlin	Harding	482	500	3.6%
Hanna	Juniper	1,009	1,007	0.2%
S. Canton	Star	808	810	0.2%
Tidd	Canton Central	633	638	0.8%
Sammis	Star	728	748	2.7%

Figure 4.4. Generation, Demand, and Interregional Power Flows on August 14, 2003, at 15:05 EDT

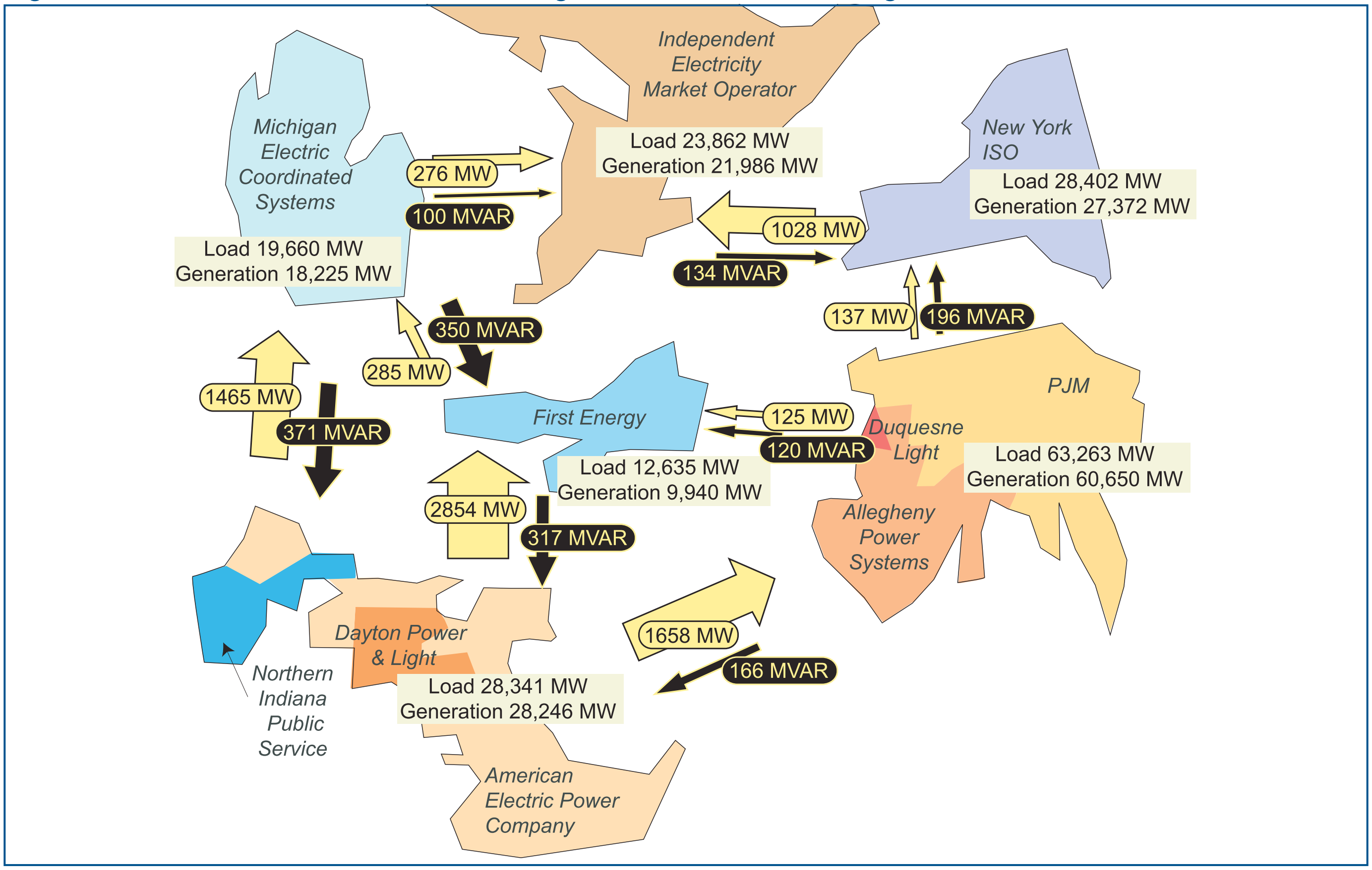
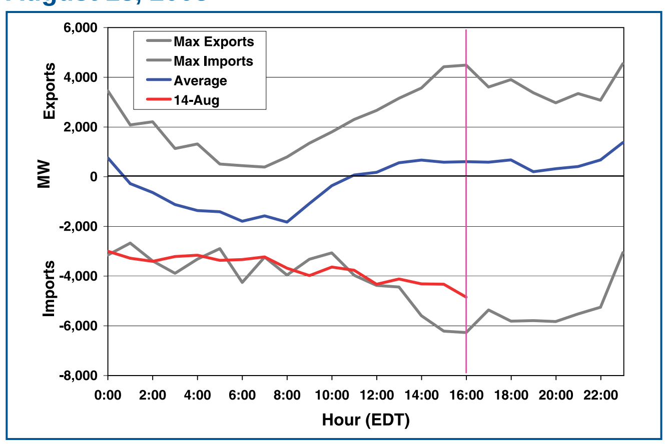


Figure 4.5 shows total scheduled imports for the entire northeast region for June through August 14, 2003. These transfers were well within the range of previous levels, as shown in Figure 4.5, and well within all established limits. In particular, on August 14 increasing amounts of the growing imports into the area were being delivered to FirstEnergy's Ohio territory to meet its increasing demand and to replace the generation lost with the trip of Eastlake 5. The level of imports into Ontario from the U.S. on August 14 was high (e.g., 1,334 MW at 16:00 EDT through the New York and Michigan ties) but not unusual, and well within IMO's import capability. Ontario is a frequent importer and exporter of power, and had imported similar and higher amounts of power several times during the summers of 2002 and 2003. PJM and Michigan also routinely import and export power across ECAR.

Figure 4.5. Scheduled Imports and Exports for the Northeast Central Region, June 1 through August 13, 2003



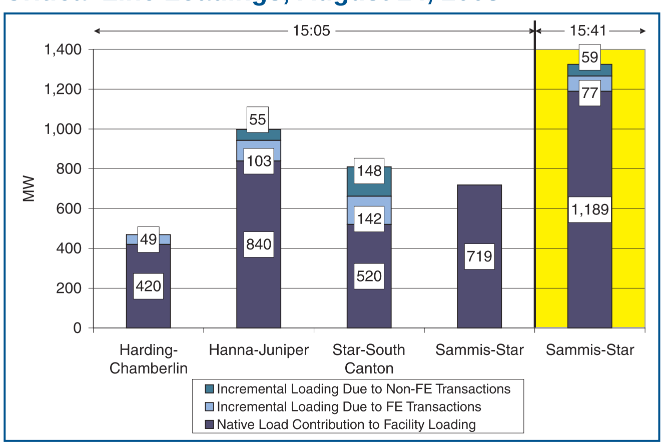
Note: These flows from within the Northeast Central Area include ECAR, PJM, IMO, NYISO, and exclude transfers from Québec, the Maritimes and New England, since the latter areas had minimal flows across the region of interest.

Some have suggested that the level of power flows into and across the Midwest was a direct cause of the blackout on August 14. Investigation team modeling proves that these flows were neither a cause nor a contributing factor to the blackout. The team used detailed modeling and simulation incorporating the NERC TagNet data on actual transactions to determine whether and how the transactions affected line loadings within the Cleveland-Akron area. The MUST (Managing Utilization of System Transmission) analytical tool uses the transactions data from TagNet along with a power flow program to determine the impact of transactions on the loading of transmission flowgates or specific facilities, calculating transfer distribution factors across the various flowgates. The MUST analysis shows that for actual flows at 15:05 EDT, only 10% of the loading on Cleveland-Akron lines was for through flows for which FE was neither the importer nor exporter.

According to real-time TagNet records, at 15:05 EDT the incremental flows due to transactions were approximately 2,800 MW flowing into the FirstEnergy control area and approximately 800 MW out of FE to Duquesne Light Company (DLCO). Among the flows into or out of the FE control area, the bulk of the flows were for transactions where FE was the recipient or the source—at 15:05 EDT the incremental flows due to transactions into FE were 1,300 MW from interconnections with PJM, AEP, DPL and MECS, and approximately 800 MW from interconnections with DLCO. But not all of that energy moved through the Cleveland-Akron area and across the lines which failed on August 14, as Figure 4.6 shows.

Figure 4.6 shows how all of the transactions flowing across the Cleveland-Akron area on the afternoon of August 14 affected line loadings at key FE facilities, organized by time and types of transactions. It shows that before the first transmission line failed, the bulk of the loading on the four critical FirstEnergy circuits—Harding-Chamberlin, Hanna-Juniper, Star-South Canton and Sammis-Star—was to serve Cleveland-Akron area native load. Flows to serve native load included transfers from FE's 1,640 MW Beaver Valley nuclear power plant and its Seneca plant, both in Pennsylvania, which have been traditionally counted by FirstEnergy not as imports but rather as in-area generation, and as such excluded from TLR curtailments. An additional small increment of line loading served transactions for which FE was either the importer or exporter, and the remaining line loading was due to through-flows initiated and received by other entities. The Star-South Canton line experienced the greatest impact from through-flows—148 MW, or 18% of the total line loading at 15:05 EDT, was due to through-flows resulting from non-FE transactions. By 15:41 EDT, right before Star-South Canton tripped—without being overloaded—the Sammis-Star line was serving almost entirely native load, with loading from through-flows down to only 4.5%.

Figure 4.6. Impacts of Transactions Flows on Critical Line Loadings, August 14, 2003



Cause 1
Inadequate System Understanding

The central point of this analysis is that because the critical lines were loaded primarily to serve native load and FE-related flows, attempts to reduce flows through transaction curtailments in and around the Cleveland-Akron area would have had minimal impact on line loadings and the declining voltage situation within that area. Rising load in the Cleveland-Akron area that afternoon was depleting the remaining reactive power reserves. Since there was no additional in-area generation, only in-area load cuts could have reduced local line loadings and improved voltage security. This is confirmed by the loadings on the Sammis-Star at 15:42 EDT, after the loss of Star-South Canton—fully 96% of the current on that line was to serve FE load and FE-related transactions, and a cut of *every non-FE through transaction* flowing across northeast Ohio would have obtained only 59 MW (4%) of relief for this specific line. This means that redispatch of generation beyond northeast Ohio would have had almost no impact upon conditions within the Cleveland-Akron area (which after 13:31 EDT had no remaining generation reserves). Equally important, cutting flows on the Star-South Canton line might not have changed subsequent events—because the line opened three times that afternoon due to tree contacts, reducing its loading would not have assured its continued operation.

Recommendations
3, page 143; 23, page 160

Power flow patterns on August 14 did not cause the blackout in the Cleveland-Akron area. But once the first four FirstEnergy lines went down, the magnitude and pattern of flows on the overall system did affect the ultimate path, location and speed of the cascade after 16:05:57 EDT.[3]

Voltages and Voltage Criteria

During the days before August 14 and throughout the morning and mid-day on August 14, voltages were depressed across parts of northern Ohio because of high air conditioning demand and other loads, and power transfers into and to a lesser extent across the region. Voltage varies by location across an electrical region, and operators monitor voltages continuously at key locations across their systems.

Entities manage voltage using long-term planning and day-ahead planning for adequate reactive supply, and real-time adjustments to operating equipment. On August 14, for example, PJM implemented routine voltage management procedures developed for heavy load conditions. Within Ohio, FE began preparations early in the afternoon of August 14, requesting capacitors to be restored to service[4] and additional voltage support from generators.[5] As the day progressed, operators across the region took additional actions, such as increasing plants' reactive power output, plant redispatch, and transformer tap changes to respond to changing voltage conditions.

Voltages at key FirstEnergy buses (points at which lines, generators, transformers, etc., converge) were declining over the afternoon of August 14. Actual measured voltage levels at the Star bus and others on FE's transmission system on August 14 were below 100% starting early in the day. At 11:00 EDT, voltage at the Star bus equaled 98.5%, declined to 97.3% after the loss of Eastlake 5 at 13:31 EDT, and dropped to 95.9% at 15:05 EDT after the loss of the Harding-Chamberlin line. FirstEnergy system operators reported this voltage performance to be typical for a warm summer day on the FirstEnergy system. The gradual decline of voltage over the early afternoon was consistent with the increase of load over the same time period, particularly given that FirstEnergy had no additional generation within the Cleveland-Akron area load pocket to provide additional reactive support.

Cause 1
Inadequate System Understanding

NERC and regional reliability councils' planning criteria and operating policies (such as NERC I.A and I.D, NPCC A-2, and ECAR Document 1) specify voltage criteria in such generic terms as: acceptable voltages under normal and emergency conditions shall be maintained within normal limits and applicable emergency limits respectively, with due recognition to avoiding voltage instability and widespread system collapse in the event of certain contingencies. Each system then defines its own

Do ATC and TTC Matter for Reliability?

Each transmission provider calculates Available Transfer Capability (ATC) and Total Transfer Capability (TTC) as part of its Open Access Transmission Tariff, and posts those on the OASIS to enable others to plan power purchase transactions. TTC is the forecast amount of electric power that can be transferred over the interconnected transmission network in a reliable manner under specific system conditions. ATCs are forecasts of the amount of transmission available for additional commercial trade above projected committed uses. These are not real-time operating security limits for the grid.

The monthly TTC and ATC values for August 2003 were first determined a year previously; those for August 14, 2003 were calculated 30 days in advance; and the hourly TTC and ATC values for the afternoon of August 14 were calculated approximately seven days ahead using forecasted system conditions. Each of these values should be updated as the forecast of system conditions changes. Thus the TTC and ATC are advance estimates for commercial purposes and do not directly reflect actual system conditions. NERC's operating procedures are designed to manage actual system conditions, not forecasts such as ATC and TTC.

Within ECAR, ATCs and TTCs are determined on a first contingency basis, assuming that only the most critical system element may be forced out of service during the relevant time period. If actual grid conditions—loads, generation dispatch, transaction requests, and equipment availability—differ from the conditions assumed previously for the ATC and TTC calculation, then the ATC and TTC have little relevance for actual system operations. Regardless of what pre-calculated ATC and TTC levels may be, system operators must use real-time monitoring and contingency analysis to track and respond to real-time facility loadings to assure that the transmission system is operated reliably.

acceptable voltage criteria based on its own system design and equipment characteristics, detailing quantified measures including acceptable minimum and maximum voltages in percentages of nominal voltage and acceptable voltage declines from the pre-contingency voltage. Good utility practice requires that these determinations be based on a full set of V-Q (voltage performance V relative to reactive power supply Q) and P-V (real power transfer P relative to voltage V)

Competition and Increased Electric Flows

Besides blaming high inter-regional power flows for causing the blackout, some blame the existence of those power flows upon wholesale electric competition. Before 1978, most power plants were owned by vertically-integrated utilities; purchases between utilities occurred when a neighbor had excess power at a price lower than other options. A notable increase in inter-regional power transfers occurred in the mid-1970s after the oil embargo, when eastern utilities with a predominance of high-cost oil-fired generation purchased coal-fired energy from Midwestern generators. The 1970s and 1980s also saw the development of strong north-to-south trade between British Columbia and California in the west, and Ontario, Québec, and New York-New England in the east. Americans benefited from Canada's competitively priced hydroelectricity and nuclear power while both sides gained from seasonal and daily banking and load balancing—Canadian provinces had winter peaking loads while most U.S. utilities had primarily summer peaks.

In the United States, wholesale power sales by independent power producers (IPPs) began after passage of the Public Utility Regulatory Policy Act of 1978, which established the right of non-utility producers to operate and sell their energy to utilities. This led to extensive IPP development in the northeast and west, increasing in-region and inter-regional power sales as utility loads grew without corresponding utility investments in transmission. In 1989, investor-owned utilities purchased 17.8% of their total energy (self-generation plus purchases) from other utilities and IPPs, compared to 37.3% in 2002; and in 1992, large public power entities purchased 36.3% of total energy (self-generation plus purchases), compared to 40.5% in 2002.[a]

In the Energy Policy Act of 1992, Congress continued to promote the development of competitive energy markets by introducing exempt wholesale generators that would compete with utility generation in wholesale electric markets (see Section 32 of the Public Utility Holding Company Act). Congress also broadened the authority of the Federal Energy Regulatory Commission to order transmission access on a case-by-case basis under Section 211 of the Federal Power Act. Consistent with this Congressional action, the Commission in Order 888 ordered all public utilities that own, operate, or control interstate transmission facilities to provide open access for sales of energy transmitted over those lines.

Competition is not the only thing that has grown over the past few decades. Between 1986 and 2002, peak demand across the United States grew by 26%, and U.S. electric generating capacity grew by 22%,[b] but U.S. transmission capacity grew little beyond the interconnection of new power plants. Specifically, "the amount of transmission capacity per unit of consumer demand declined during the past two decades and . . . is expected to drop further in the next decade."[c]

Load-serving entities today purchase power for the same reason they did before the advent of competition—to serve their customers with low-cost energy—and the U.S. Department of Energy estimates that Americans save almost $13 billion (U.S.) annually on the cost of electricity from the opportunity to buy from distant, economical sources. But it is likely that the increased loads and flows across a transmission grid that has experienced little new investment is causing greater "stress upon the hardware, software and human beings that are the critical components of the system."[d] A thorough study of these issues has not been possible as part of the Task Force's investigation, but such a study would be worthwhile. For more discussion, see Recommendation 12, page 148.

[a]RDI PowerDat database.
[b]U.S. Energy Information Administration, *Energy Annual Data Book*, 2003 edition.
[c]Dr. Eric Hirst, "Expanding U.S. Transmission Capacity," August 2000, p. vii.
[d]Letter from Michael H. Dworkin, Chairman, State of Vermont Public Service Board, February 11, 2004, to Alison Silverstein and Jimmy Glotfelty.

analyses for a wide range of system conditions. Table 4.3 compares the voltage criteria used by FirstEnergy and other relevant transmission operators in the region. As this table shows, FE uses minimum acceptable normal voltages which are lower than and incompatible with those used by its interconnected neighbors.

Recommendation 23, page 160

Cause 1
Inadequate System Understanding

The investigation team probed deeply into voltage management issues within the Cleveland-Akron area. As noted previously, a power system with higher operating voltage and larger reactive power reserves is more resilient or robust in the face of load increases and operational contingencies. Higher transmission voltages enable higher power transfer capabilities and reduce transmission line losses (both real and reactive). For the Cleveland-Akron area, FE has been operating the system with the minimum voltage level at 90% of nominal rating, with alarms set at 92%.[6] The criteria allow for a single contingency to occur if voltage remains above 90%. The team conducted extensive voltage stability studies (discussed below), concluding that FE's 90% minimum voltage level was not only far less stringent than nearby interconnected systems (most of which set the pre-contingency minimum voltage criteria at 95%), but was not adequate for secure system operations.

Examination of the Form 715 filings made by Ohio Edison, FE's predecessor company, for 1994 through 1997 indicate that Ohio Edison used a pre-contingency bus voltage criteria of 95 to 105 % and 90% emergency post-contingency voltage, with acceptable change in voltage no greater than 5%. These historic criteria were compatible with neighboring transmission operator practices.

A look at voltage levels across the region illustrates the difference between FE's voltage situation on August 14 and that of its neighbors.

Cause 1
Inadequate System Understanding

Figure 4.7 shows the profile of voltage levels at key buses from southeast Michigan across Ohio into western Pennsylvania from August 11 through 14 and for several hours on August 14. These transects show that across the area, voltage levels were consistently lower at the 345-kV buses in the Cleveland-Akron area (from Beaver to Hanna on the west to east plot and from Avon Lake to Star on the north to south plot) for the three days and the 13:00 to 15:00 EDT period preceding the blackout. Voltage was consistently and considerably higher at the outer ends of each transect, where it never dropped below 96% even on August 14. These profiles also show clearly the decline of voltage over the afternoon of August 14, with voltage at the Harding bus at 15:00 EDT just below 96% before the Harding-Chamberlin line tripped at 15:05 EDT, and dropping down to around 93% at 16:00 EDT after the loss of lines and load in the immediate area.

Cause 1
Inadequate System Understanding

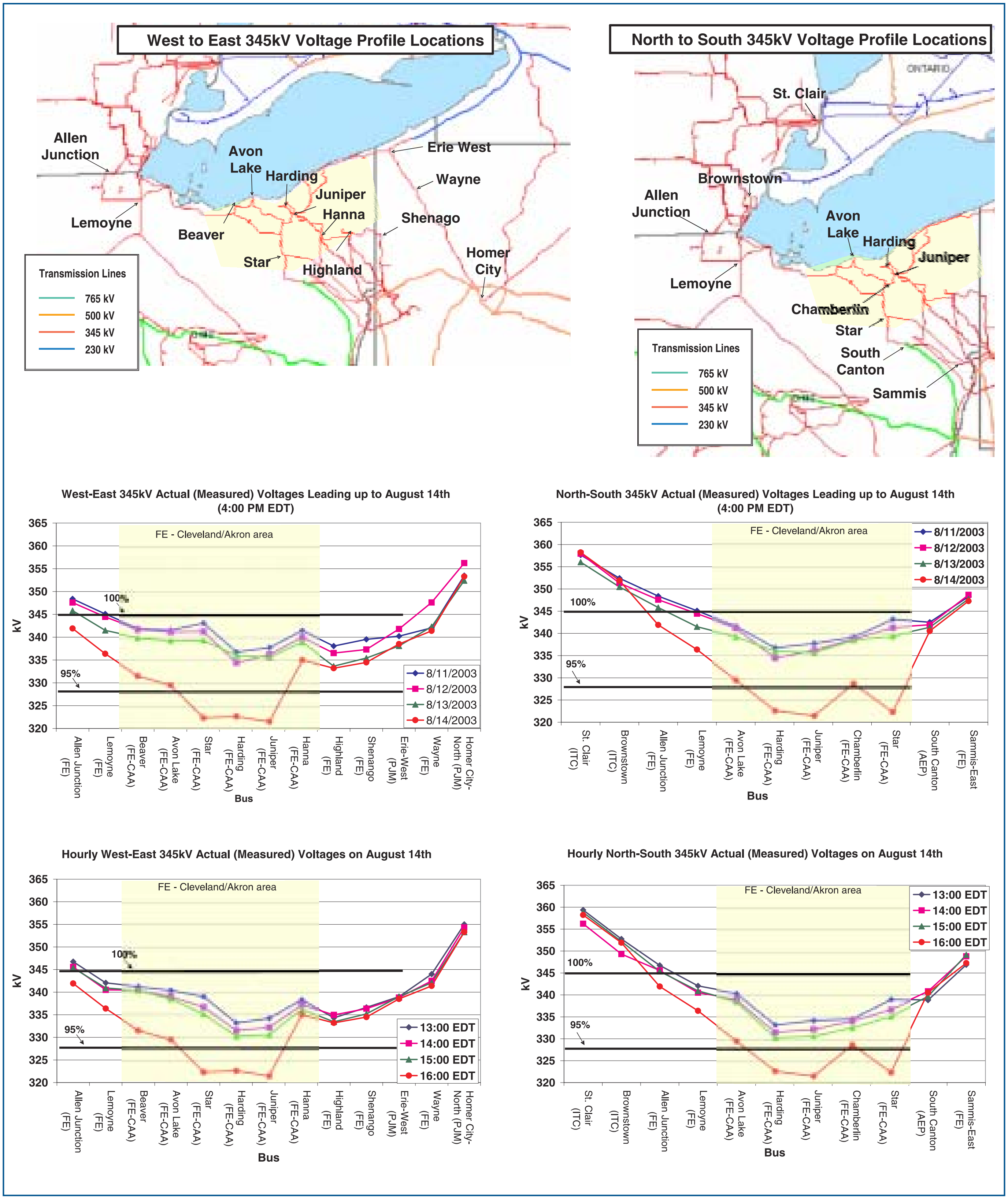
Using actual data provided by FE, ITC, AEP and PJM, Figure 4.8 shows the availability of reactive reserves (the difference between reactive power generated and the maximum reactive capability) within the Cleveland-Akron area and four regions surrounding it, from ITC to PJM. On the afternoon of August 14, the graph shows that reactive power generation was heavily taxed in the Cleveland-Akron area but that extensive MVAr reserves were available in the neighboring areas. As the afternoon progressed, reactive reserves diminished for all five regions as load grew. But reactive reserves were fully depleted within the Cleveland-Akron area by 16:00 EDT without drawing down the reserves in neighboring areas, which remained at scheduled voltages. The region as a whole had sufficient reactive reserves, but because reactive power cannot be transported far but must be supplied from

Table 4.3. Comparison of Voltage Criteria (Percent)

345 kV/138 kV	FE	PJM	AEP	METC[a]	ITC[b]	MISO	IMO[c]
High	105	105	105	105	105	105	110
Normal Low	90	95	95	97	95	95	98
Emergency/Post N-1 Low.	90	92	90[d]		87		94
Maximum N-1 deviation	5[e]			5			10

[a]Applies to 138 kV only. 345 kV not specified.
[b]Applies to 345 kV only. Min-max normal voltage for 120 kV and 230 kV is 93-105%.
[c]500 kV.
[d]92% for 138 kV.
[e]10% for 138 kV.

Figure 4.7. Actual Voltages Across the Ohio Area Before and On August 14, 2003



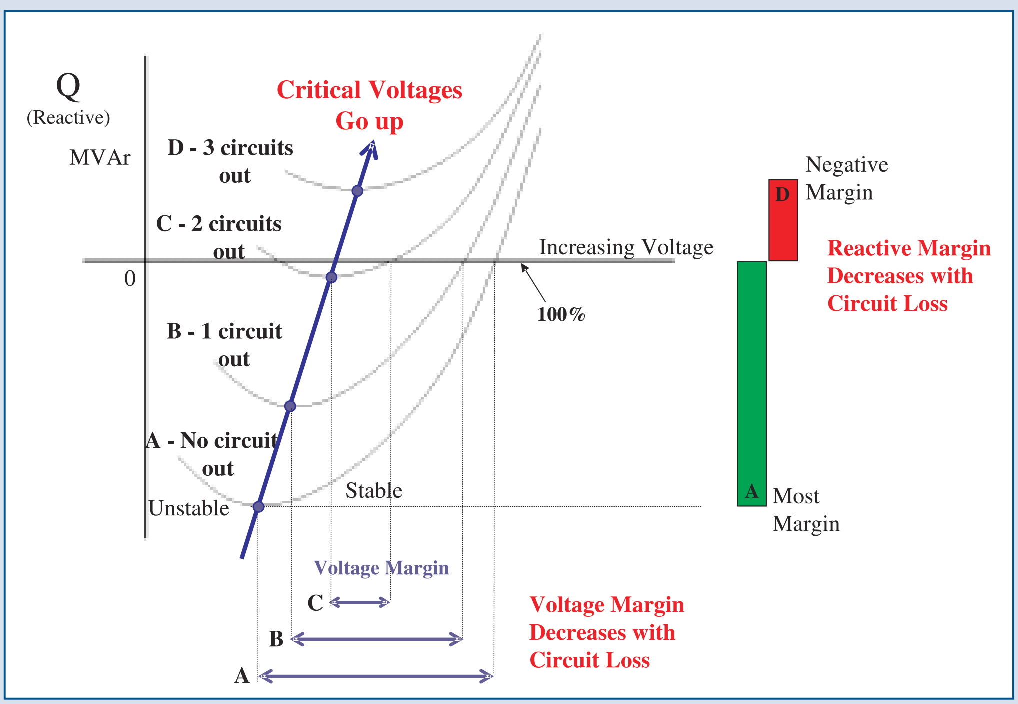
Voltage Stability Analysis

Voltage instability or voltage collapse occurs on a power system when voltages progressively decline until stable operating voltages can no longer be maintained. This is precipitated by an imbalance of reactive power supply and demand, resulting from one or more changes in system conditions including increased real or reactive loads, high power transfers, or the loss of generation or transmission facilities. Unlike the phenomenon of transient instability, where generators swing out of synchronism with the rest of the power system within a few seconds or less after a critical fault, voltage instability can occur gradually within tens of seconds or minutes.

Voltage instability is best studied using V-Q (voltage relative to reactive power) and P-V (real power relative to voltage) analysis. V-Q analysis evaluates the reactive power required at a bus to maintain stable voltage at that bus. A simulated reactive power source is added to the bus, the voltage schedule at the bus is adjusted in small steps from an initial operating point, and power flows are solved to determine the change in reactive power demand resulting from the change in voltage. Under stable operating conditions, when voltage increases the reactive power requirement also increases, and when voltage falls the reactive requirement also falls. But when voltage is lowered at the bus and the reactive requirement at that bus begins to increase (rather than continuing to decrease), the system becomes unstable. The voltage point corresponding to the transition from stable to unstable conditions is known as the "critical voltage," and the reactive power level at that point is the "reactive margin." The desired operating voltage level should be well above the critical voltage with a large buffer for changes in prevailing system conditions and contingencies. Similarly, reactive margins should be large to assure robust voltage levels and secure, stable system performance.

The illustration below shows a series of V-Q curves. The lowest curve, A, reflects baseline conditions for the grid with all facilities available. Each higher curve represents the same loads and transfers for the region modeled, but with another contingency event (a circuit loss) occurring to make the system less stable. With each additional contingency, the critical voltage rises (the point on the horizontal axis corresponding to the lowest point on the curve) and the reactive margin decreases (the difference between the reactive power at the critical voltage and the zero point on the vertical axis). This means the system is closer to instability.

V-Q (Voltage-Reactive Power) Curves



Voltage Stability Analysis (Continued)

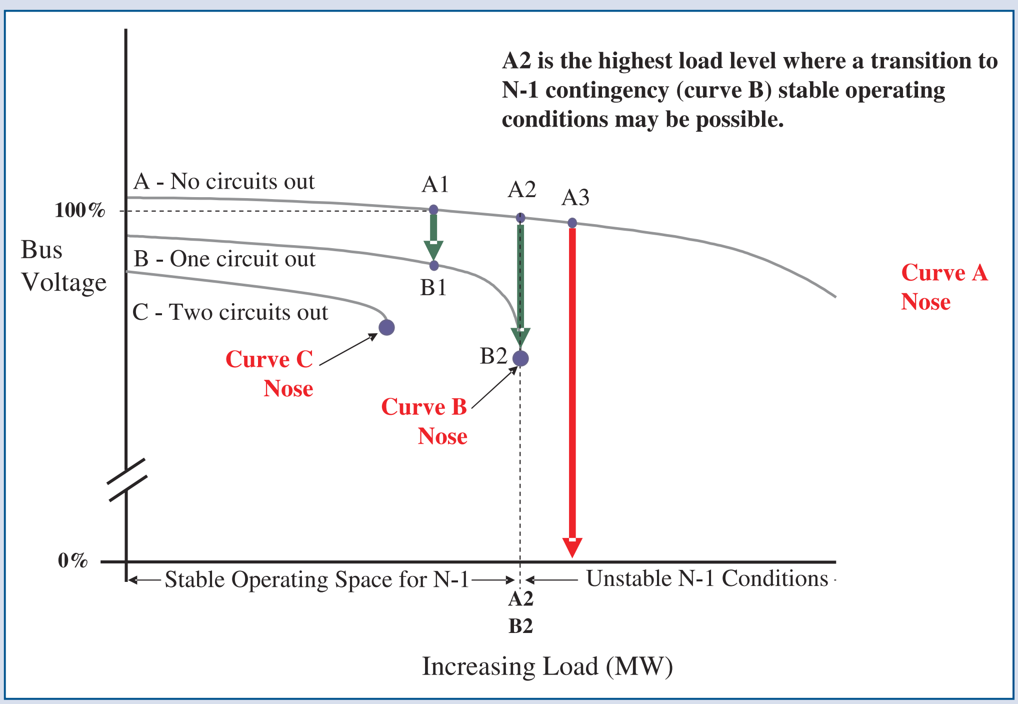
V-Q analyses and experience with heavily loaded power systems confirm that critical voltage levels can rise above the 95% level traditionally considered as normal. Thus voltage magnitude alone is a poor indicator of voltage stability and V-Q analysis must be carried out for several critical buses in a local area, covering a range of load and generation conditions and known contingencies that affect voltages at these buses.

P-V analysis (real power relative to voltage) is a companion tool which determines the real power transfer capability across a transmission interface for load supply or a power transfer. Starting from a base case system state, a series of load flows with increasing power transfers are solved while monitoring voltages at critical buses. When power transfers reach a high enough level a stable voltage cannot be sustained and the power flow model fails to solve. The point where the power flow last solved corresponds to the critical voltage level found in the V-Q curve for those conditions. On a P-V curve (see below), this point is called the "nose" of the curve.

This set of P-V curves illustrates that for baseline conditions shown in curve A, voltage remains relatively steady (change along the vertical axis) as load increases within the region (moving out along the horizontal axis). System conditions are secure and stable in the area above the "nose" of the curve. After a contingency occurs, such as a transmission circuit or generator trip, the new condition set is represented by curve B, with lower voltages (relative to curve A) for any load on curve B. As the operator's charge is to keep the system stable against the next worst contingency, the system must be operated to stay well inside the load level for the nose of curve B. If the B contingency occurs, there is a next worst contingency curve inside curve B, and the operator must adjust the system to pull back operations to within the safe, buffered space represented by curve C.

The investigation team conducted extensive V-Q and P-V analyses for the area around Cleveland-Akron for the conditions in effect on August 14, 2003. Team members examined over fifty 345-kV and 138-kV buses across the systems of FirstEnergy, AEP, International Transmission Company, Duquesne Light Company, Alleghany Power Systems and Dayton Power & Light. The V-Q analysis alone involved over 10,000 power flow simulations using a system model with more than 43,000 buses and 57,000 lines and transformers. The P-V analyses used the same model and data sets. Both examined conditions and combinations of contingencies for critical times before and after key events on the FirstEnergy system on the day of the blackout.

P-V (Power-Voltage) Curves



local sources, these healthy reserves nearby could not support the Cleveland-Akron area's reactive power deficiency and growing voltage problems. Even FE's own generation in the Ohio Valley had reactive reserves that could not support the sagging voltages inside the Cleveland-Akron area.

Cause 1
Inadequate System Understanding

An important consideration in reactive power planning is to ensure an appropriate balance between static and dynamic reactive power resources across the interconnected system (as specified in NERC Planning Standard 1D.S1). With so little generation left in the Cleveland-Akron area on August 14, the area's dynamic reactive reserves were depleted and the area relied heavily on static compensation to respond to changing system conditions and support voltages. But a system relying on static compensation can experience a gradual voltage degradation followed by a sudden drop in voltage stability—the P-V curve for such a system has a very steep slope close to the nose, where voltage collapses. On August 14, the lack of adequate dynamic reactive reserves, coupled with not knowing the critical voltages and maximum import capability to serve native load, left the Cleveland-Akron area in a very vulnerable state.

Recommendation
23, page 160

Past System Events and Adequacy of System Studies

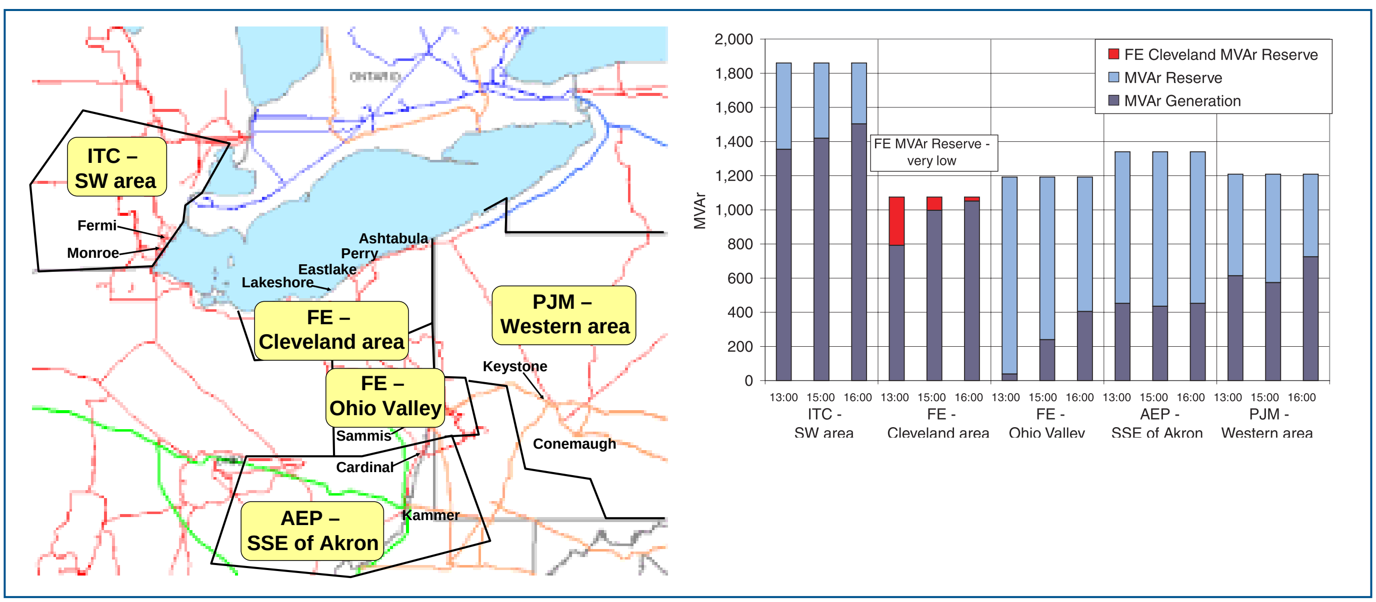
Cause 1
Inadequate System Understanding

In June 1994, with three generators in the Cleveland area out on maintenance, inadequate reactive reserves and falling voltages in the Cleveland area forced Cleveland Electric Illuminating (CEI, a predecessor company to FirstEnergy) to shed load within Cleveland (a municipal utility and wholesale transmission and purchase customers within CEI's control area) to avoid voltage collapse.[7] The Cleveland-Akron area's voltage problems were well-known and reflected in the stringent voltage criteria used by control area operators until 1998.[8]

Cause 1
Inadequate System Understanding

In the summer of 2002, AEP's South Canton 765 kV to 345 kV transformer (which connects to FirstEnergy's Star 345-kV line) experienced eleven days of severe overloading when actual loadings exceeded normal rating and contingency loadings were at or above summer emergency ratings. In each instance, AEP took all available actions short of load shedding to return the system to a secure state, including TLRs, switching, and dispatch adjustments. These excessive loadings were

Figure 4.8. Reactive Reserves Around Ohio on August 14, 2003, for Representative Generators in the Area



Note: These reactive reserve MVAr margins were calculated for the five regions for the following plants: (1) Cleveland area of FirstEnergy—Ashtabula 5, Perry 1, Eastlake 1, Eastlake 3, Lakeshore 18; (2) Northern central portion of AEP near FirstEnergy (South-Southeast of Akron)—Cardinal 1, Cardinal 2, Cardinal 3, Kammer 2, Kammer 3; (3) Southwest area of MECS (ITC)—Fermi 1, Monroe 2, Monroe 3, Monroe 4; (4) Ohio Valley portion of FirstEnergy—Sammis 4, Sammis 5, Sammis 6, Sammis 7; (5) Western portion of PJM—Keystone 1, Conemaugh 1, Conemaugh 2.

calculated to have diminished the remaining life of the transformer by 30%. AEP replaced this single phase transformer in the winter of 2002-03, marginally increasing the capacity of the South Canton transformer bank.

Following these events, AEP conducted extensive modeling to understand the impact of a potential outage of this transformer. That modeling revealed that loss of the South Canton transformer, especially if it occurred in combination with outages of other critical facilities, would cause significant low voltages and overloads on both the AEP and FirstEnergy systems. AEP shared these findings with FirstEnergy in a meeting on January 10, 2003.[9]

AEP subsequently completed a set of system studies, including long range studies for 2007, which included both single contingency and extreme

Independent Power Producers and Reactive Power

Independent power producers (IPPs) are power plants that are not owned by utilities. They operate according to market opportunities and their contractual agreements with utilities, and may or may not be under the direct control of grid operators. An IPP's reactive power obligations are determined by the terms of its contractual interconnection agreement with the local transmission owner. Under routine conditions, some IPPs provide limited reactive power because they are not required or paid to produce it; they are only paid to produce active power. (Generation of reactive power by a generator can require scaling back generation of active power.) Some contracts, however, compensate IPPs for following a voltage schedule set by the system operator, which requires the IPP to vary its output of reactive power as system conditions change. Further, contracts typically require increased reactive power production from IPPs when it is requested by the control area operator during times of a system emergency. In some contracts, provisions call for the payment of opportunity costs to IPPs when they are called on for reactive power (i.e., they are paid the value of foregone active power production).

Thus, the suggestion that IPPs may have contributed to the difficulties of reliability management on August 14 because they don't provide reactive power is misplaced. What the IPP is required to produce is governed by contractual arrangements, which usually include provisions for contributions to reliability, particularly during system emergencies. More importantly, it is the responsibility of system planners and operators, not IPPs, to plan for reactive power requirements and make any short-term arrangements needed to ensure that adequate reactive power resources will be available.

Power Flow Simulation of Pre-Cascade Conditions

The bulk power system has no memory. It does not matter if frequencies or voltage were unusual an hour, a day, or a month earlier. What matters for reliability are loadings on facilities, voltages, and system frequency at a given moment and the collective capability of these system components at that same moment to withstand a contingency without exceeding thermal, voltage, or stability limits.

Power system engineers use a technique called power flow simulation to reproduce known operating conditions at a specific time by calibrating an initial simulation to observed voltages and line flows. The calibrated simulation can then be used to answer a series of "what if" questions to determine whether the system was in a safe operating state at that time. The "what if" questions consist of systematically simulating outages by removing key elements (e.g., generators or transmission lines) one by one and reassessing the system each time to determine whether line or voltage limits would be exceeded. If a limit is exceeded, the system is not in a secure state. As described in Chapter 2, NERC operating policies require operators, upon finding that their system is not in a reliable state, to take immediate actions to restore the system to a reliable state as soon as possible and within a maximum of 30 minutes.

To analyze the evolution of the system on the afternoon of August 14, this process was followed to model several points in time, corresponding to key transmission line trips. For each point, three solutions were obtained: (1) conditions immediately before a facility tripped off; (2) conditions immediately after the trip; and (3) conditions created by any automatic actions taken following the trip.

disturbance possibilities. These studies showed that with heavy transfers to the north, expected overloading of the South Canton transformer and depressed voltages would occur following the loss of the Perry unit and the loss of the Tidd-Canton Central 345-kV line, and probable cascading into voltage collapse across northeast Ohio would occur for nine different double contingency combinations of generation and transmission or transmission and transmission outages.[10] AEP shared these findings with FirstEnergy in a meeting on May 21, 2003. Meeting notes indicate that "neither AEP or FE were able to identify any changes in transmission configuration or operating procedures which could be used during 2003 summer to be able to control power flows through the S. Canton bank."[11] Meeting notes include an action item that both "AEP and FE would share the results of these studies and expected performance for 2003 summer with their Management and Operations personnel."[12]

Reliability coordinators and control areas prepare regional and seasonal studies for a variety of system-stressing scenarios, to better understand potential operational situations, vulnerabilities, risks, and solutions. However, the studies FirstEnergy relied on—both by FirstEnergy and ECAR—were not robust, thorough, or up-to-date. This left FE's planners and operators with a deficient understanding of their system's capabilities and risks under a range of system conditions. None of the past voltage events noted above or the significant risks identified in AEP's 2002-2003 studies are reflected in any FirstEnergy or ECAR seasonal or longer-term planning studies or operating protocols available to the investigation team.

Cause 1
Inadequate System Understanding

FE's 2003 Summer Study focused primarily on single-contingency (N-1) events, and did not consider significant multiple contingency losses and security. FirstEnergy examined only thermal limits and looked at voltage only to assure that voltage levels remained within range of 90 to 105% of nominal voltage on the 345 kV and 138 kV network. The study assumed that only the Davis-Besse power plant (883 MW) would be out of service at peak load of 13,206 MW; on August 14, peak load reached 12,166 MW and scheduled generation outages included Davis-Besse, Sammis 3 (180 MW) and Eastlake 4 (240 MW), with Eastlake 5 (597 MW) lost in real time. The study assumed that all transmission facilities would be in service; on August 14, scheduled transmission outages included the Eastlake #62 345/138 kV transformer and the Fox #1 138-kV capacitor, with other capacitors down in real time. Last, the study assumed a single set of import and export conditions, rather than testing a wider range of generation dispatch, import-export, and inter-regional transfer conditions. Overall, the summer study posited less stressful system conditions than actually occurred August 14, 2003 (when load was well below historic peak demand). It did not examine system sensitivity to key parameters to determine system operating limits within the constraints of transient stability, voltage stability, and thermal capability.

Recommendation
23, page 160

Cause 1
Inadequate System Understanding

FirstEnergy has historically relied upon the ECAR regional assessments to identify anticipated reactive power requirements and recommended corrective actions. But ECAR over the past five years has not conducted any detailed analysis of the Cleveland-Akron area and its voltage-constrained import capability—although that constraint had been an operational consideration in the 1990s and was documented in testimony filed in 1996 with the Federal Energy Regulatory Commission.[13] The voltage-constrained import capability was not studied; FirstEnergy had modified the criteria around 1998 and no longer followed the tighter voltage limits used earlier. In the ECAR "2003 Summer Assessment of Transmission System Performance," dated May 2003, First Energy's Individual Company Assessment identified potential overloads for the loss of both Star 345/138 transformers, but did not mention any expected voltage limitation.

Recommendation
3, page 143

FE participates in ECAR studies that evaluate extreme contingencies and combinations of events. ECAR does not conduct exacting region-wide analyses, but compiles individual members' internal studies of N-2 and multiple contingencies (which may include loss of more than one circuit, loss of a transmission corridor with several transmission lines, loss of a major substation or generator, or loss of a major load pocket). The last such study conducted was published in 2000, projecting system conditions for 2003. That study did not include any contingency cases that resulted in 345-kV line overloading or voltage violations on 345-kV buses. FE reported no evidence of a risk of cascading, but reported that some local load would be lost and generation redispatch would be needed to alleviate some thermal overloads.

ECAR and Organizational Independence

ECAR was established in 1967 as a regional reliability council, to "augment the reliability of the members' electricity supply systems through coordination of the planning and operation of the members' generation and transmission facilities."[a] ECAR's membership includes 29 major electricity suppliers serving more than 36 million people.

ECAR's annual budget for 2003 was $5.15 million (U.S.), including $1.775 million (U.S.) paid to fund NERC.[b] These costs are funded by its members in a formula that reflects megawatts generated, megawatt load served, and miles of high voltage lines. AEP, ECAR's largest member, pays about 15% of total ECAR expenses; FirstEnergy pays approximately 8 to 10%.[c]

Utilities "whose generation and transmission have an impact on the reliability of the interconnected electric systems" of the region are full ECAR members, while small utilities, independent power producers, and marketers can be associate members.[d] Its Executive Board has 22 seats, one for each full member utility or major supplier (including every control area operator in ECAR). Associate members do not have voting rights, either on the Board or on the technical committees which do all the work and policy-setting for the ECAR region.

All of the policy and technical decisions for ECAR, including all interpretations of NERC guidelines, policies, and standards within ECAR, are developed by committees (called "panels"), staffed by representatives from the ECAR member companies. Work allocation and leadership within ECAR are provided by the Board, the Coordination Review Committee, and the Market Interface Committee.

ECAR has a staff of 18 full-time employees, headquartered in Akron, Ohio. The staff provides engineering analysis and support to the various committees and working groups. Ohio Edison, a FirstEnergy subsidiary, administers salary, benefits, and accounting services for ECAR. ECAR employees automatically become part of Ohio Edison's (FirstEnergy's) 401(k) retirement plan; they receive FE stock as a matching share to employee 401(k) investments and can purchase FE stock as well. Neither ECAR staff nor board members are required to divest stock holdings in ECAR member companies.[e] Despite the close link between FirstEnergy's financial health and the interest of ECAR's staff and management, the investigation team has found no evidence to suggest that ECAR staff favor FirstEnergy's interests relative to other members.

ECAR decisions appear to be dominated by the member control areas, which have consistently allowed the continuation of past practices within each control area to meet NERC requirements, rather than insisting on more stringent, consistent requirements for such matters as operating voltage criteria or planning studies. ECAR member representatives also staff the reliability council's audit program, measuring individual control area compliance against local standards and interpretations. It is difficult for an entity dominated by its members to find that the members' standards and practices are inadequate. But it should also be recognized that NERC's broadly worded and ambiguous standards have enabled and facilitated the lax interpretation of reliability requirements within ECAR over the years.

Recommendations
2, page 143; 3, page 143

[a]ECAR "Executive Manager's Remarks," http://www.ecar.org.
[b]Interview with Brantley Eldridge, ECAR Executive Manager, March 10, 2004.
[c]Interview with Brantley Eldridge, ECAR Executive Manager, March 3, 2004.
[d]ECAR "executive Manager's Remarks," http://www.ecar.org.
[e]Interview with Brantley Eldridge, ECAR Executive Manager, March 3, 2004.

Model-Based Analysis of the State of the Regional Power System at 15:05 EDT, Before the Loss of FE's Harding-Chamberlin 345-kV Line

As the first step in modeling the August 14 blackout, the investigation team established a base case by creating a power flow simulation for the entire Eastern Interconnection and benchmarking it to recorded system conditions at 15:05 EDT on August 14. The team started with a projected summer 2003 power flow case for the Eastern Interconnection developed in the spring of 2003 by the Regional Reliability Councils to establish guidelines for safe operations for the coming summer. The level of detail involved in this region-wide power flow case far exceeds that normally considered by individual control areas and reliability coordinators. It consists of a detailed representation of more than 43,000 buses, 57,600 transmission lines, and all major generating stations across the northern U.S. and eastern Canada. The team revised the summer power flow case to match recorded generation, demand, and power interchange levels among control areas at 15:05 EDT on August 14. The benchmarking consisted of matching the calculated voltages and line flows to recorded observations at more than 1,500 locations within the grid. Thousands of hours of effort were required to benchmark the model satisfactorily to observed conditions at 15:05 EDT.

Once the base case was benchmarked, the team ran a contingency analysis that considered more than 800 possible events—including the loss of the Harding-Chamberlin 345-kV line—as points of departure from the 15:05 EDT case. None of these contingencies resulted in a violation of a transmission line loading or bus voltage limit prior to the trip of FE's Harding-Chamberlin 345-kV line. That is, according to these simulations, the system at 15:05 EDT was capable of safe operation following the occurrence of any of the tested contingencies. From an electrical standpoint, therefore, *before* 15:05 EDT the Eastern Interconnection was being operated within all established limits and in full compliance with NERC's operating policies. However, *after* loss of the Harding-Chamberlin 345-kV line, the system would have exceeded emergency ratings immediately on several lines for two of the contingencies studied—in other words, it would no longer be operating in compliance with NERC Operating Policy A.2 because it could not be brought back into a secure operating condition within 30 minutes.

Perry Nuclear Plant as a First Contingency

Investigation team modeling demonstrates that the Perry nuclear unit (1,255 MW near Lake Erie) is critical to the voltage stability of the Cleveland-Akron area in general and particularly on August 14. The modeling reveals that had Perry tripped before 15:05 EDT, voltage levels at key FirstEnergy buses would have fallen close to 93% with only a 150 MW of area load margin (2% of the Cleveland-Akron area load); but had Perry been lost after the Harding-Chamberlin line went down at 15:05 EDT, the Cleveland-Akron area would have been close to voltage collapse.

Cause 1
Inadequate System Understanding

Perry and Eastlake 5 together have a combined real power capability of 1,852 MW and reactive capability of 930 MVAr. If one of these units is lost, it is necessary to immediately replace the lost generation with MW and MVAr imports (although reactive power does not travel far under heavy loading); without quick-start generation or spinning reserves or dynamic reactive reserves inside the Cleveland-Akron area, system security may be jeopardized. On August 14, as noted previously, there were no significant spinning reserves remaining within the Cleveland-Akron area following the loss of Eastlake 5 at 13:31 EDT. If Perry had been lost FE would have been unable to meet the 30-minute security adjustment requirement of NERC's Operating Policy 2, without the ability to shed load quickly. The loss of Eastlake 5 followed by the loss of Perry are contingencies that should be assessed in the operations planning timeframe, to develop measures to readjust the system between contingencies. Since FirstEnergy did not conduct such contingency analysis planning and develop these advance measures, it was in violation of NERC Planning Standard 1A, Category C3.

Recommendation
23, page 160

This operating condition is not news. Historically, the loss of Perry at full output has been recognized as FE's most critical single contingency for the Cleveland Electric Illuminating area, as documented by FE's 1998 Summer Import Capability study. Perry's MW and MVAr total output capability exceeded the import capability of any of the critical 345-kV circuits into the Cleveland-Akron area after the loss of Eastlake 5 at 13:31 EDT. This means that if the Perry plant had been lost on August 14 after Eastlake 5 went down—or on many other days with similar loads and outages—it would have been difficult or impossible for FE operators to adjust the system within 30 minutes to prepare for the next critical contingency, as required by NERC Operating Policy A.2. In real-time operations, operators would have to calculate operating limits and prepare to use the last resort of manually shedding large blocks of load before the second contingency, or immediately after it if automatic load-shedding is available.

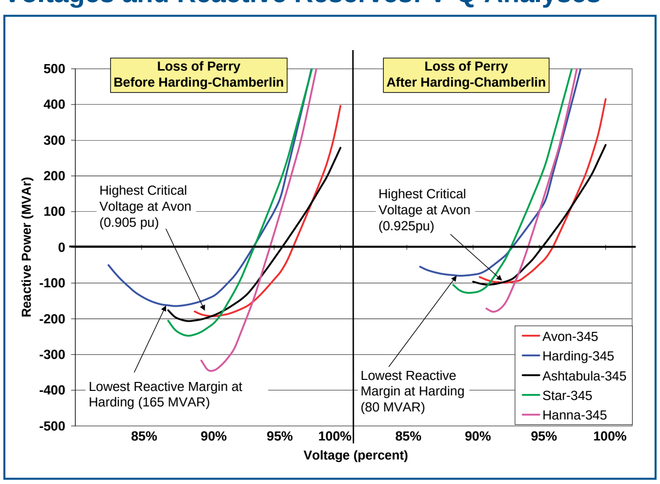
Cause 1
Inadequate System Understanding

The investigation team could not find FirstEnergy contingency plans or operational procedures for operators to manage the FirstEnergy control area and protect the Cleveland-Akron area from the unexpected loss of the Perry plant.

To examine the impact of this worst contingency on the Cleveland-Akron area on August 14, Figure 4.9 shows the V-Q curves for key buses in the Cleveland-Akron area at 15:05 EDT, before and after the loss of the Harding-Chamberlin line. The curves on the left look at the impact of the loss of Perry before the Harding-Chamberlin trip, while the curves on the right show the impact had the nuclear plant been lost after Harding-Chamberlin went out of service. Had Perry gone down *before* the Harding-Chamberlin outage, reactive margins at key FE buses would have been minimal (with the tightest margin at the Harding bus, read along the Y-axis) and the critical voltage (the point before voltage collapse, read along the X-axis) at

Recommendation
23, page 160

Figure 4.9. Loss of the Perry Unit Hurts Critical Voltages and Reactive Reserves: V-Q Analyses



the Avon bus would have risen to 90.5%—uncomfortably close to the limits which FE considered as an acceptable operating range. But had the Perry unit gone off-line *after* Harding-Chamberlin, reactive margins at all these buses would have been even tighter (with only 60 MVAr at the Harding bus), and critical voltage at Avon would have risen to 92.5%, worse than FE's 90% minimum acceptable voltage. The system at this point would be very close to voltage instability. If the first line outage on August 14, 2003, had been at Hanna-Juniper rather than at Harding-Chamberlin, the FirstEnergy system could not have withstood the loss of the Perry plant.

Cause 1
Inadequate System Understanding

The above analysis assumed load levels consistent with August 14. But temperatures were not particularly high that day and loads were nowhere near FE's historic load level of 13,229 MW for the control area (in August 2002). Therefore the investigation team looked at what might have happened in the Cleveland-Akron area had loads neared the historic peak—approximately 625 MW higher than the 6,715 MW peak load in the Cleveland-Akron area in 2003. Figure 4.10 uses P-V analysis to show the impact of increased load levels on voltages at the Star bus with and without the Perry unit before the loss of the Harding-Chamberlin line at 15:05 EDT. The top line shows that with the Perry plant available, local load could have increased by 625 MW and voltage at Star would have remained above 95%. But the bottom line, simulating the loss of Perry, indicates that load could only have increased by about 150 MW before voltage at Star would have become unsolvable, indicating no voltage stability margin and depending on load dynamics, possible voltage collapse.

The above analyses indicate that the Cleveland-Akron area was highly vulnerable on the afternoon of August 14. Although the system was compliant with NERC Operating Policy 2A.1 for single contingency reliability before the loss of the Harding-Chamberlin line at 15:05 EDT, had FE lost the Perry plant its system would have neared voltage instability or could have gone into a full voltage collapse immediately if the Cleveland-Akron area load were 150 MW higher. It is worth noting that this could have happened on August 14—at 13:43 EDT that afternoon, the Perry plant operator called the control area operator to warn about low voltages. At 15:36:51 EDT the Perry plant operator called FirstEnergy's system control center to ask about voltage spikes at the plant's main transformer.[14] At 15:42:49 EDT the Perry operator called the FirstEnergy operator to say, "I'm still getting a lot of voltage spikes and swings on the generator . . . . I'm taking field volts pretty close to where I'll trip the turbine off."[15]

System Frequency

Assuming stable conditions, the system frequency is the same across an interconnected grid at any particular moment. System frequency will vary from moment to moment, however, depending on the second-to-second balance between aggregate generation and aggregate demand across the interconnection. System frequency is monitored on a continuous basis.

There were no significant or unusual frequency oscillations in the Eastern Interconnection on August 14 prior to 16:09 EDT compared to prior days, and frequency was well within the bounds of safe operating practices. System frequency variation was not a cause or precursor of the initiation of the blackout. But once the cascade began, the large frequency swings that occurred early on became a principal means by which the blackout spread across a wide area.

Figure 4.11 shows Eastern Interconnection frequency on August 14, 2003. Frequency declines or increases from a mismatch between generation and load on the order of about 3,200 MW per 0.1 Hertz (alternatively, a change in load or generation of 1,000 MW would cause a frequency change of about ±0.031 Hz). Significant frequency excursions reflect large changes in load relative to generation and could cause unscheduled flows between control areas and even, in the extreme, cause automatic under-frequency load-shedding or automatic generator trips.

The investigation team examined Eastern Interconnection frequency and Area Control Error (ACE) for August 14, 2003 and the entire month of August, looking for patterns and anomalies. Extensive analysis using Fast Fourier Transforms (described in the NERC Technical Report) revealed no unusual variations. Rather, transforms using various time samples of average frequency (from 1 hour to 6 seconds in length) indicate instead that the Eastern Interconnection exhibits regular deviations.[16]

The largest deviations in frequency occur at regular intervals. These intervals reflect interchange

Frequency Management

Each control area is responsible for maintaining a balance between its generation and demand. If persistent under-frequency occurs, at least one control area somewhere is "leaning on the grid," meaning that it is taking unscheduled electricity from the grid, which both depresses system frequency and creates unscheduled power flows. In practice, minor deviations at the control area level are routine; it is very difficult to maintain an exact balance between generation and demand. Accordingly, NERC has established operating rules that specify maximum permissible deviations, and focus on prohibiting persistent deviations, but not instantaneous ones. NERC monitors the performance of control areas through specific measures of control performance that gauge how accurately each control area matches its load and generation.

Figure 4.10. Impact of Perry Unit Outage on Cleveland-Akron Area Voltage Stability

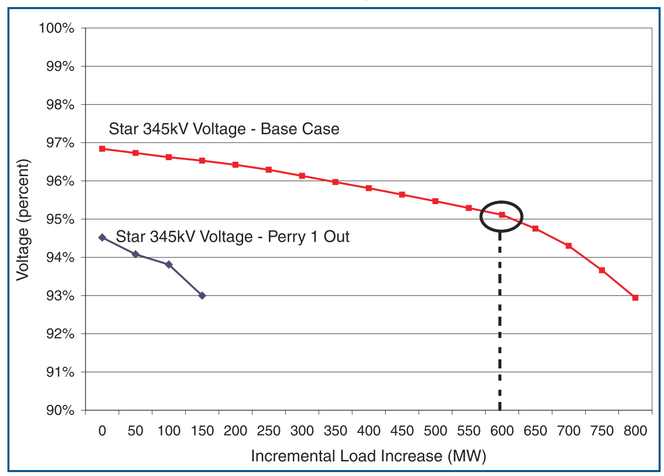
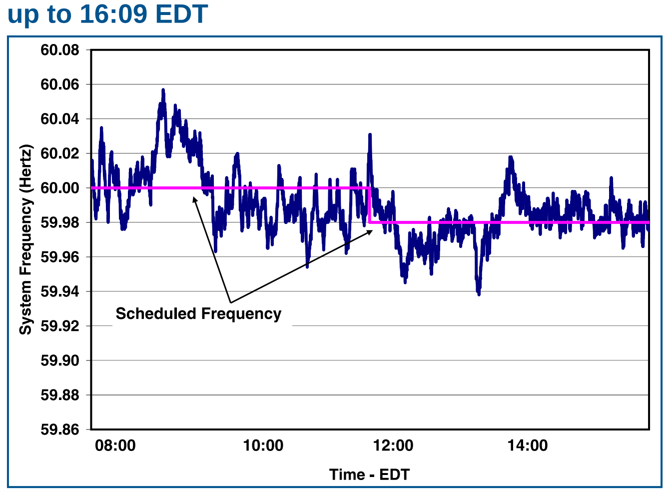
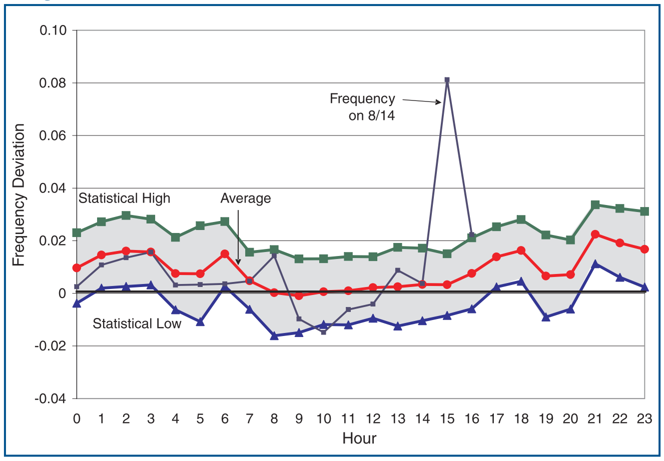


Figure 4.11. Frequency on August 14, 2003, up to 16:09 EDT



schedule changes at the peak to off-peak schedule changes (06:00 to 07:00 and 21:00 to 22:00, as shown in Figure 4.12) and on regular hourly and half-hour schedule changes as power plants ramp up and down to serve scheduled purchases and interchanges. Frequency tends to run high in the early part of the day because extra generation capacity is committed and waiting to be dispatched for the afternoon peak, and then runs lower in the afternoon as load rises relative to available generation and spinning reserve. The investigation team concluded that frequency data collection and frequency management in the Eastern Interconnection should be improved, but that frequency oscillations before 16:09 EDT on August 14 had no effect on the blackout.

Figure 4.12. Hourly Deviations in Eastern Interconnection Frequency for the Month of August 2003



Conclusion

Determining that the system was in a reliable operational state at 15:05 EDT is extremely significant for understanding the causes of the blackout. It means that none of the electrical conditions on the system before 15:05 EDT was a cause of the blackout. This eliminates low voltages earlier in the day or on prior days, the unavailability of individual generators or transmission lines (either individually or in combination with one another), high power flows to Canada, unusual system frequencies, and many other issues as direct, principal or sole causes of the blackout.

Although FirstEnergy's system was technically in secure electrical condition before 15:05 EDT, it was still highly vulnerable, because some of its assumptions and limits were not accurate for safe operating criteria. Analysis of Cleveland-Akron area voltages and reactive margins shows that FirstEnergy was operating that system on the very edge of NERC operational reliability standards, and that it could have been compromised by a number of potentially disruptive scenarios that were foreseeable by thorough planning and operations studies. A system with this little reactive margin would leave little room for adjustment, with few relief actions available to operators in the face of single or multiple contingencies. As the next chapter will show, the vulnerability created by inadequate system planning and understanding was exacerbated because the FirstEnergy operators were not adequately trained or prepared to recognize and deal with emergency situations.

Endnotes

[1] FE transcripts, Channel 14, 13:33:44.

[2] FE transcripts, Channel 14 at 13:21:05; channel 3 at 13:41:54; 15:30:36.

[3] "ECAR Investigation of August 14, 2003 Blackout by Major System Disturbance Analysis Task Force, Recommendations Report," page 6.

[4] Transmission operator at FE requested the restoration of the Avon Substation capacitor bank #2. Example at Channel 3, 13:33:40. However, no additional capacitors were available.

[5] From 13:13 through 13:28, reliability operator at FE called nine plant operators to request additional voltage support. Examples at Channel 16, 13:13:18, 13:15:49, 13:16:44, 13:20:44, 13:22:07, 13:23:24, 13:24:38, 13:26:04, 13:28:40.

[6] DOE/NERC fact-finding meeting, September 2003, statement by Mr. Steve Morgan (FE), PR0890803, lines 5-23.

[7] See 72 FERC 61,040, the order issued for FERC dockets EL 94-75-000 and EL 94-80-000, for details of this incident.

[8] Testimony by Stanley Szwed, Vice President of Engineering and Planning, Centerior Service Company (Cleveland Electric Illuminating Company and Toledo Edison), FERC docket EL 94-75-000, February 22, 1996.

[9] Presentation notes for January 10, 2003 meeting between AEP and FirstEnergy, and meeting summary notes by Paul Johnson, AEP Manager, East Bulk Transmission Planning, January 10, 2003.

[10] "Talking Points" for May 21, 2003 meeting between AEP and FirstEnergy, prepared by AEP.

[11] Memo, "Summary of AEP/FE Meeting on 5/21/03," by Scott P. Lockwood, AEP, May 29, 2003.

[12] *Ibid.*

[13] Testimony by Stanley Szwed, Vice President of Engineering and Planning, Centerior Service Company (Cleveland Electric Illuminating Company and Toledo Edison), FERC docket EL 94-75-000, February 22, 1996.

[14] FE transcript, Channel 8.

[15] FE transcript, Channel 8.

[16] See NERC Blackout Investigation Technical Reports, to be released in 2004.

5. How and Why the Blackout Began in Ohio

Summary

This chapter explains the major events—electrical, computer, and human—that occurred as the blackout evolved on August 14, 2003, and identifies the causes of the initiation of the blackout. The period covered in this chapter begins at 12:15 Eastern Daylight Time (EDT) on August 14, 2003 when inaccurate input data rendered MISO's state estimator (a system monitoring tool) ineffective. At 13:31 EDT, FE's Eastlake 5 generation unit tripped and shut down automatically. Shortly after 14:14 EDT, the alarm and logging system in FE's control room failed and was not restored until after the blackout. After 15:05 EDT, some of FE's 345-kV transmission lines began tripping out because the lines were contacting overgrown trees within the lines' right-of-way areas.

By around 15:46 EDT when FE, MISO and neighboring utilities had begun to realize that the FE system was in jeopardy, the only way that the blackout might have been averted would have been to drop at least 1,500 MW of load around Cleveland and Akron. No such effort was made, however, and by 15:46 EDT it may already have been too late for a large load-shed to make any difference. After 15:46 EDT, the loss of some of FE's key 345-kV lines in northern Ohio caused its underlying network of 138-kV lines to begin to fail, leading in turn to the loss of FE's Sammis-Star 345-kV line at 16:06 EDT. The chapter concludes with the loss of FE's Sammis-Star line, the event that triggered the uncontrollable 345 kV cascade portion of the blackout sequence.

The loss of the Sammis-Star line triggered the cascade because it shut down the 345-kV path into northern Ohio from eastern Ohio. Although the area around Akron, Ohio was already blacked out due to earlier events, most of northern Ohio remained interconnected and electricity demand was high. This meant that the loss of the heavily overloaded Sammis-Star line instantly created major and unsustainable burdens on lines in adjacent areas, and the cascade spread rapidly as lines and generating units automatically tripped by protective relay action to avoid physical damage.

Chapter Organization

This chapter is divided into several phases that correlate to major changes within the FirstEnergy system and the surrounding area in the hours leading up to the cascade:

- **Phase 1:** A normal afternoon degrades
- **Phase 2:** FE's computer failures
- **Phase 3:** Three FE 345-kV transmission line failures and many phone calls
- **Phase 4:** The collapse of the FE 138-kV system and the loss of the Sammis-Star line.

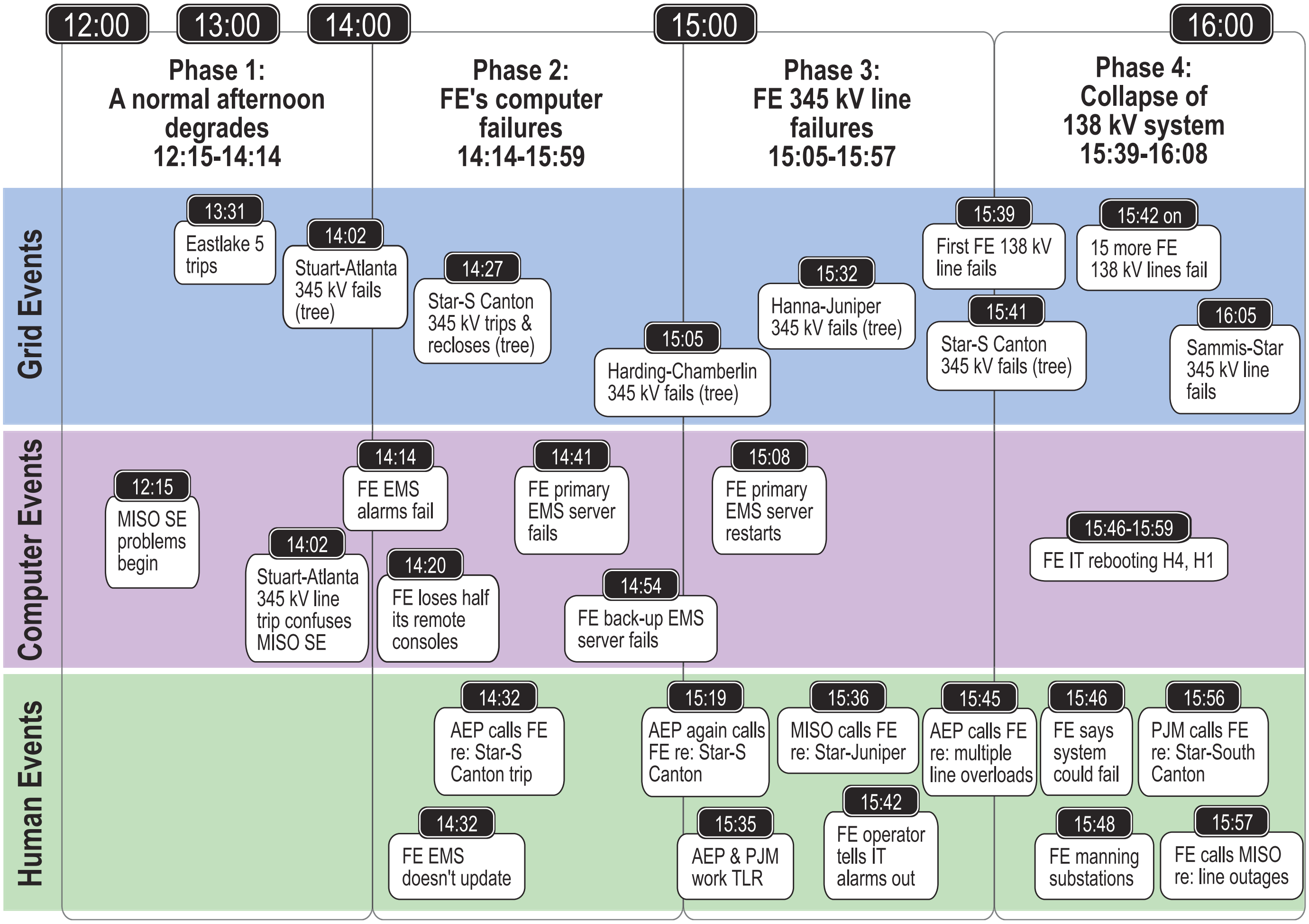
Key events within each phase are summarized in Figure 5.1, a timeline of major events in the origin of the blackout in Ohio. The discussion that follows highlights and explains these significant events within each phase and explains how the events were related to one another and to the cascade. Specific causes of the blackout and associated recommendations are identified by icons.

Phase 1: A Normal Afternoon Degrades: 12:15 EDT to 14:14 EDT

Overview of This Phase

Northern Ohio was experiencing an ordinary August afternoon, with loads moderately high to serve air conditioning demand, consuming high levels of reactive power. With two of Cleveland's active and reactive power production anchors already shut down (Davis-Besse and Eastlake 4), the loss of the Eastlake 5 unit at 13:31 EDT further depleted critical voltage support for the Cleveland-Akron area. Detailed simulation modeling reveals that the loss of Eastlake 5 was a significant factor in the outage later that afternoon—with Eastlake 5 out of service, transmission line

Figure 5.1. Timeline: Start of the Blackout in Ohio



loadings were notably higher but well within normal ratings. After the loss of FE's Harding-Chamberlin line at 15:05 EDT, the system eventually became unable to sustain additional contingencies, even though key 345 kV line loadings did not exceed their normal ratings. Had Eastlake 5 remained in service, subsequent line loadings would have been lower. Loss of Eastlake 5, however, did not initiate the blackout. Rather, subsequent computer failures leading to the loss of situational awareness in FE's control room and the loss of key FE transmission lines due to contacts with trees were the most important causes.

At 14:02 EDT, Dayton Power & Light's (DPL) Stuart-Atlanta 345-kV line tripped off-line due to a tree contact. This line had no direct electrical effect on FE's system—but it did affect MISO's performance as reliability coordinator, even though PJM is the reliability coordinator for the DPL line. One of MISO's primary system condition evaluation tools, its state estimator, was unable to assess system conditions for most of the period between 12:15 and 15:34 EDT, due to a combination of human error and the effect of the loss of DPL's Stuart-Atlanta line on other MISO lines as reflected in the state estimator's calculations. Without an effective state estimator, MISO was unable to perform contingency analyses of generation and line losses within its reliability zone. Therefore, through 15:34 EDT MISO could not determine that with Eastlake 5 down, other transmission lines would overload if FE lost a major transmission line, and could not issue appropriate warnings and operational instructions.

In the investigation interviews, all utilities, control area operators, and reliability coordinators indicated that the morning of August 14 was a reasonably typical day.[1] FE managers referred to it as peak load conditions on a less than peak load day. Dispatchers consistently said that while voltages were low, they were consistent with historical voltages.[2] Throughout the morning and early afternoon of August 14, FE reported a growing need for voltage support in the upper Midwest.

The FE reliability operator was concerned about low voltage conditions on the FE system as early as 13:13 EDT. He asked for voltage support (i.e., increased reactive power output) from FE's interconnected generators. Plants were operating in automatic voltage control mode (reacting to system voltage conditions and needs rather than constant reactive power output). As directed in FE's Manual of Operations,[3] the FE reliability operator began to call plant operators to ask for additional voltage support from their units. He noted to most of them that system voltages were sagging "all over." Several mentioned that they were already at or near their reactive output limits. None were asked to reduce their real power output to be able to produce more reactive output. He called the Sammis plant at 13:13 EDT, West Lorain at 13:15 EDT, Eastlake at 13:16 EDT, made three calls to unidentified plants between 13:20 EDT and 13:23 EDT, a "Unit 9" at 13:24 EDT, and two more at 13:26 EDT and 13:28 EDT.[4] The operators worked to get shunt capacitors at Avon that were out of service restored to support voltage,[5] but those capacitors could not be restored to service.

Following the loss of Eastlake 5 at 13:31 EDT, FE's operators' concern about voltage levels increased. They called Bay Shore at 13:41 EDT and Perry at

Energy Management System (EMS) and Decision Support Tools

Operators look at potential problems that could arise on their systems by using contingency analyses, driven from state estimation, that are fed by data collected by the SCADA system.

SCADA: System operators use **S**ystem **C**ontrol **a**nd **D**ata **A**cquisition systems to acquire power system data and control power system equipment. SCADA systems have three types of elements: field remote terminal units (RTUs), communication to and between the RTUs, and one or more Master Stations.

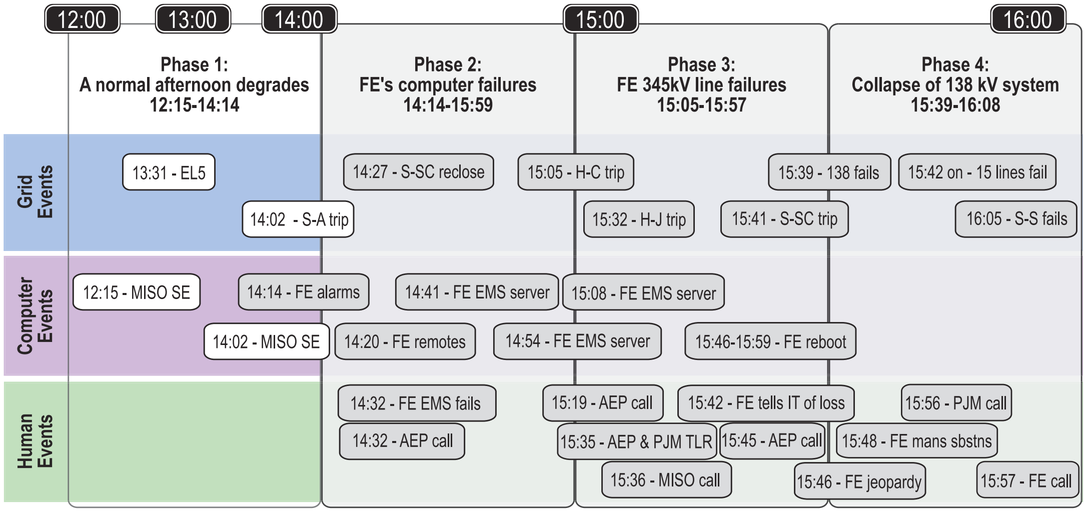
Field RTUs, installed at generation plants and substations, are combination data gathering and device control units. They gather and provide information of interest to system operators, such as the status of a breaker (switch), the voltage on a line or the amount of real and reactive power being produced by a generator, and execute control operations such as opening or closing a breaker. Telecommunications facilities, such as telephone lines or microwave radio channels, are provided for the field RTUs so they can communicate with one or more SCADA Master Stations or, less commonly, with each other.

Master stations are the pieces of the SCADA system that initiate a cycle of data gathering from the field RTUs over the communications facilities, with time cycles ranging from every few seconds to as long as several minutes. In many power systems, Master Stations are fully integrated into the control room, serving as the direct interface to the Energy Management System (EMS), receiving incoming data from the field RTUs and relaying control operations commands to the field devices for execution.

State Estimation: Transmission system operators must have visibility (condition information) over their own transmission facilities, and recognize the impact on their own systems of events and facilities in neighboring systems. To accomplish this, system state estimators use the real-time data measurements available on a subset of those facilities in a complex mathematical model of the power system that reflects the configuration of the network (which facilities are in service and which are not) and real-time system condition data to estimate voltage at each bus, and to estimate real and reactive power flow quantities on each line or through each transformer. Reliability coordinators and control areas that have them commonly run a state estimator on regular intervals or only as the need arises (i.e., upon demand). Not all control areas use state estimators.

Contingency Analysis: Given the state estimator's representation of current system conditions, a system operator or planner uses contingency analysis to analyze the impact of specific outages (lines, generators, or other equipment) or higher load, flow, or generation levels on the security of the system. The contingency analysis should identify problems such as line overloads or voltage violations that will occur if a new event (contingency) happens on the system. Some transmission operators and control areas have and use state estimators to produce base cases from which to analyze next contingencies ("N-1," meaning normal system minus 1 key element) from the current conditions. This tool is typically used to assess the reliability of system operation. Many control areas do not use real time contingency analysis tools, but others run them on demand following potentially significant system events.

Figure 5.2. Timeline Phase 1



13:43 EDT to ask the plants for more voltage support. Again, while there was substantial effort to support voltages in the Ohio area, FirstEnergy personnel characterized the conditions as not being unusual for a peak load day, although this was not an all-time (or record) peak load day.[6]

Key Phase 1 Events

1A) 12:15 EDT to 16:04 EDT: MISO's state estimator software solution was compromised, and MISO's single contingency reliability assessment became unavailable.

1B) 13:31:34 EDT: Eastlake Unit 5 generation tripped in northern Ohio.

1C) 14:02 EDT: Stuart-Atlanta 345-kV transmission line tripped in southern Ohio.

1A) MISO's State Estimator Was Turned Off: 12:15 EDT to 16:04 EDT

It is common for reliability coordinators and control areas to use a state estimator (SE) to improve the accuracy of the raw sampled data they have for the electric system by mathematically processing raw data to make it consistent with the electrical system model. The resulting information on equipment voltages and loadings is used in software tools such as real time contingency analysis (RTCA) to simulate various conditions and outages to evaluate the reliability of the power system. The RTCA tool is used to alert operators if the system is operating insecurely; it can be run either on a regular schedule (e.g., every 5 minutes), when triggered by some system event (e.g., the loss of a power plant or transmission line), or when initiated by an operator. MISO usually runs the SE every 5 minutes, and the RTCA less frequently. If the model does not have accurate and timely information about key pieces of system equipment or if key input data are wrong, the state estimator may be unable to reach a solution or it will reach a solution that is labeled as having a high degree of error. In August, MISO considered its SE and RTCA tools to be still under development and not fully mature; those systems have since been completed and placed into full operation.

On August 14 at about 12:15 EDT, MISO's state estimator produced a solution with a high mismatch (outside the bounds of acceptable error). This was traced to an outage of Cinergy's Bloomington-Denois Creek 230-kV line—although it was out of service, its status was not updated in MISO's state estimator. Line status information within MISO's reliability coordination area is transmitted to MISO by the ECAR data network or direct links and is intended to be automatically linked to the SE. This requires coordinated data naming as well as instructions that link the data to the tools. For this line, the automatic linkage of line status to the state estimator had not yet been established. The line status was corrected and MISO's analyst obtained a good SE solution at 13:00 EDT and an RTCA solution at 13:07 EDT. However, to troubleshoot this problem the analyst had turned off the automatic trigger that runs the state estimator every five minutes. After fixing the problem he forgot to re-enable it, so although he had successfully run the SE and RTCA manually to reach a set of correct system analyses, the tools were not returned to normal automatic operation. Thinking the system had been successfully restored, the analyst went to lunch.

Cause 4
Inadequate RC Diagnostic Support

The fact that the state estimator was not running automatically on its regular 5-minute schedule was discovered about 14:40 EDT. The automatic trigger was re-enabled but again the state estimator failed to solve successfully. This time investigation identified the Stuart-Atlanta 345-kV line outage (which occurred at 14:02 EDT) to be the likely cause. This line is within the Dayton Power and Light control area in southern Ohio and is under PJM's reliability umbrella rather than MISO's. Even though it affects electrical flows within MISO, its status had not been automatically linked to MISO's state estimator.

The discrepancy between actual measured system flows (with Stuart-Atlanta off-line) and the MISO model (which assumed Stuart-Atlanta on-line) prevented the state estimator from solving correctly. At 15:09 EDT, when informed by the system engineer that the Stuart-Atlanta line appeared to be the problem, the MISO operator said (mistakenly) that this line was in service. The system engineer then tried unsuccessfully to reach a solution with the Stuart-Atlanta line modeled as in service until approximately 15:29 EDT, when the MISO operator called PJM to verify the correct status. After they determined that Stuart-Atlanta had tripped, they updated the state estimator and it solved successfully. The RTCA was then run manually and solved successfully at 15:41 EDT. MISO's state estimator and contingency analysis were back under full automatic operation and solving effectively by 16:04 EDT, about two minutes before the start of the cascade.

In summary, the MISO state estimator and real time contingency analysis tools were effectively out of service between 12:15 EDT and 16:04 EDT. This prevented MISO from promptly performing precontingency "early warning" assessments of power system reliability over the afternoon of August 14.

Recommendations
3, page 143; 6, page 147; 30, page 163

1B) Eastlake Unit 5 Tripped: 13:31 EDT

Eastlake Unit 5 (rated at 597 MW) is in northern Ohio along the southern shore of Lake Erie, connected to FE's 345-kV transmission system (Figure 5.3). The Cleveland and Akron loads are generally supported by generation from a combination of the Eastlake, Perry and Davis-Besse units, along with significant imports, particularly from 9,100 MW of generation located along the Ohio and Pennsylvania border. The unavailability of Eastlake 4 and Davis-Besse meant that FE had to import more energy into the Cleveland-Akron area to support its load.

When Eastlake 5 dropped off-line, replacement power transfers and the associated reactive power to support the imports to the local area contributed to the additional line loadings in the region. At 15:00 EDT on August 14, FE's load was approximately 12,080 MW, and they were importing about 2,575 MW, 21% of their total. FE's system reactive power needs rose further.

Cause 1
Inadequate System Understanding

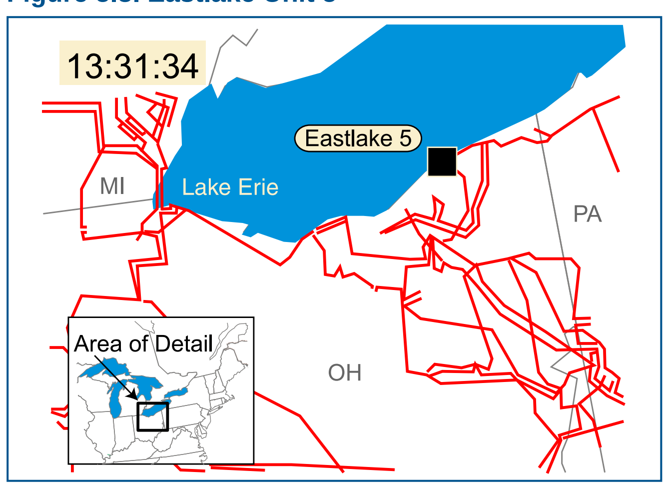
The investigation team's system simulations indicate that the loss of Eastlake 5 was a critical step in the sequence of events. Contingency analysis simulation of the conditions following the loss of the Harding-Chamberlin 345-kV circuit at 15:05 EDT showed that the system would be unable to sustain some contingencies without line overloads above emergency ratings. However, when Eastlake 5 was modeled as in service and fully available in those simulations, all overloads above emergency limits were eliminated, even with the loss of Harding-Chamberlin.

Recommendation
23, page 160

Cause 2
Inadequate Situational Awareness

FE did not perform a contingency analysis after the loss of Eastlake 5 at 13:31 EDT to determine whether the loss of further lines or plants would put their system at risk. FE also did not perform a contingency analysis after the loss of Harding-Chamberlin at 15:05 EDT (in part because they did not know that it had tripped out of service), nor does the utility routinely conduct such studies.[7] Thus FE did not discover that their system was no longer in an N-1

Figure 5.3. Eastlake Unit 5



secure state at 15:05 EDT, and that operator action was needed to remedy the situation.

Recommendations
3, page 143, 22, page 159

1C) Stuart-Atlanta 345-kV Line Tripped: 14:02 EDT

Cause 1
Inadequate System Understanding

The Stuart-Atlanta 345-kV transmission line is in the control area of Dayton Power and Light. At 14:02 EDT the line tripped due to contact with a tree, causing a short circuit to ground, and locked out. Investigation team modeling reveals that the loss of DPL's Stuart-Atlanta line had no significant electrical effect on power flows and voltages in the FE area. The team examined the security of FE's system, testing power flows and voltage levels with the combination of plant and line outages that evolved on the afternoon of August 14. This analysis shows that the availability or unavailability of the Stuart-Atlanta 345-kV line did not change the capability or performance of FE's system or affect any line loadings within the FE system, either immediately after its trip or later that afternoon. The only reason why Stuart-Atlanta matters to the blackout is because it contributed to the failure of MISO's state estimator to operate effectively, so MISO could not fully identify FE's precarious system conditions until 16:04 EDT.[8]

Data Exchanged for Operational Reliability

The topology of the electric system is essentially the road map of the grid. It is determined by how each generating unit and substation is connected to all other facilities in the system and at what voltage levels, the size of the individual transmission wires, the electrical characteristics of each of those connections, and where and when series and shunt reactive devices are in service. All of these elements affect the system's impedance—the physics of how and where power will flow across the system. Topology and impedance are modeled in power-flow programs, state estimators, and contingency analysis software used to evaluate and manage the system.

Topology processors are used as front-end processors for state estimators and operational display and alarm systems. They convert the digital telemetry of breaker and switch status to be used by state estimators, and for displays showing lines being opened or closed or reactive devices in or out of service.

A variety of up-to-date information on the elements of the system must be collected and exchanged for modeled topology to be accurate in real time. If data on the condition of system elements are incorrect, a state estimator will not successfully solve or converge because the real-world line flows and voltages being reported will disagree with the modeled solution.

Data Needed: A variety of operational data is collected and exchanged between control areas and reliability coordinators to monitor system performance, conduct reliability analyses, manage congestion, and perform energy accounting. The data exchanged range from real-time system data, which is exchanged every 2 to 4 seconds, to OASIS reservations and electronic tags that identify individual energy transactions between parties. Much of these data are collected through operators' SCADA systems.

ICCP: Real-time operational data is exchanged and shared as rapidly as it is collected. The data is passed between the control centers using an Inter-Control Center Communications Protocol (ICCP), often over private frame relay networks. NERC operates one such network, known as NERCNet. ICCP data are used for minute-to-minute operations to monitor system conditions and control the system, and include items such as line flows, voltages, generation levels, dynamic interchange schedules, area control error (ACE), and system frequency, as well as in state estimators and contingency analysis tools.

IDC: Since the actual power flows along the path of least resistance in accordance with the laws of physics, the NERC Interchange Distribution Calculator (IDC) is used to determine where it will actually flow. The IDC is a computer software package that calculates the impacts of existing or proposed power transfers on the transmission components of the Eastern Interconnection. The IDC uses a power flow model of the interconnection, representing over 40,000 substation buses, 55,000 lines and transformers, and more than 6,000 generators. This model calculates transfer distribution factors (TDFs), which tell how a power transfer would load up each system

(continued on page 51)

Phase 2: FE's Computer Failures: 14:14 EDT to 15:59 EDT

Overview of This Phase

Starting around 14:14 EDT, FE's control room operators lost the alarm function that provided audible and visual indications when a significant piece of equipment changed from an acceptable to a problematic condition. Shortly thereafter, the EMS system lost a number of its remote control consoles. Next it lost the primary server computer that was hosting the alarm function, and then the backup server such that all functions that were being supported on these servers were stopped at 14:54 EDT. However, for over an hour no one in FE's control room grasped that their computer systems were not operating properly, even though FE's Information Technology support staff knew of the problems and were working to solve them, and the absence of alarms and other symptoms offered many clues to the operators of the EMS system's impaired state. Thus, without a functioning EMS or the knowledge that it had failed, FE's system operators remained unaware that their electrical system condition was beginning to

Data Exchanged for Operational Reliability (Continued)

element, and outage transfer distribution factors (OTDFs), which tell how much power would be transferred to a system element if another specific system element were lost.

The IDC model is updated through the NERC System Data Exchange (SDX) system to reflect line outages, load levels, and generation outages. Power transfer information is input to the IDC through the NERC electronic tagging (E-Tag) system.

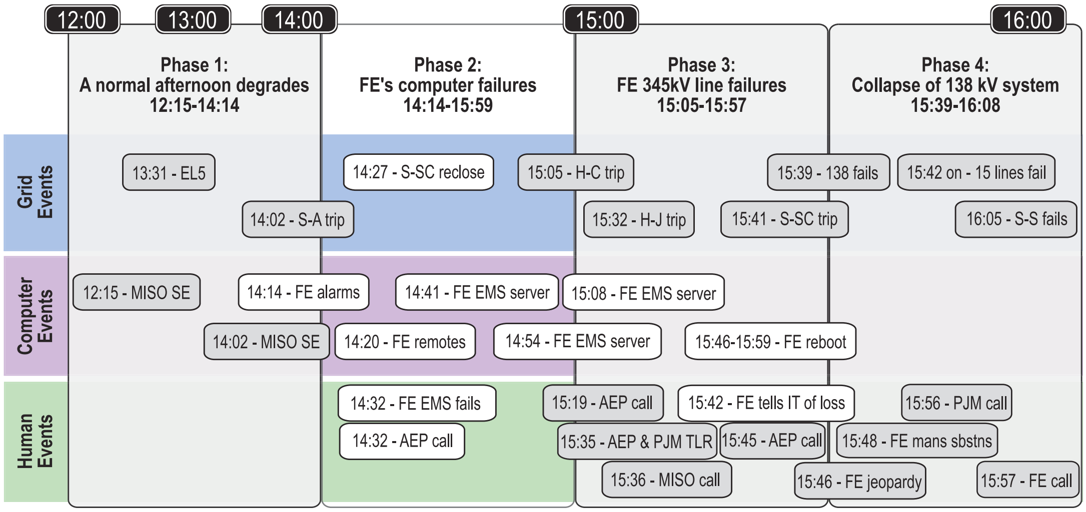
SDX: The IDC depends on element status information, exchanged over the NERC System Data Exchange (SDX) system, to keep the system topology current in its powerflow model of the Eastern Interconnection. The SDX distributes generation and transmission outage information to all operators, as well as demand and operating reserve projections for the next 48 hours. These data are used to update the IDC model, which is used to calculate the impact of power transfers across the system on individual transmission system elements. There is no current requirement for how quickly asset owners must report changes in element status (such as a line outage) to the SDX—some entities update it with facility status only once a day, while others submit new information immediately after an event occurs. NERC is now developing a requirement for regular information update submittals that is scheduled to take effect in the summer of 2004.

SDX data are used by some control centers to keep their topology up-to-date for areas of the interconnection that are not observable through direct telemetry or ICCP data. A number of transmission providers also use these data to update their transmission models for short-term determination of available transmission capability (ATC).

E-Tags: All inter-control area power transfers are electronically tagged (E-Tag) with critical information for use in reliability coordination and congestion management systems, particularly the IDC in the Eastern Interconnection. The Western Interconnection also exchanges tagging information for reliability coordination and use in its unscheduled flow mitigation system. An E-Tag includes information about the size of the transfer, when it starts and stops, where it starts and ends, and the transmission service providers along its entire contract path, the priorities of the transmission service being used, and other pertinent details of the transaction. More than 100,000 E-Tags are exchanged every month, representing about 100,000 GWh of transactions. The information in the E-Tags is used to facilitate curtailments as needed for congestion management.

Voice Communications: Voice communication between control area operators and reliability is an essential part of exchanging operational data. When telemetry or electronic communications fail, some essential data values have to be manually entered into SCADA systems, state estimators, energy scheduling and accounting software, and contingency analysis systems. Direct voice contact between operators enables them to replace key data with readings from the other systems' telemetry, or surmise what an appropriate value for manual replacement should be. Also, when operators see spurious readings or suspicious flows, direct discussions with neighboring control centers can help avert problems like those experienced on August 14, 2003.

Figure 5.4. Timeline Phase 2



degrade. Unknowingly, they used the outdated system condition information they did have to discount information from others about growing system problems.

Key Events in This Phase

2A) 14:14 EDT: FE alarm and logging software failed. Neither FE's control room operators nor FE's IT EMS support personnel were aware of the alarm failure.

2B) 14:20 EDT: Several FE remote EMS consoles failed. FE's Information Technology (IT) engineer was computer auto-paged.

2C) 14:27:16 EDT: Star-South Canton 345-kV transmission line tripped and successfully reclosed.

2D) 14:32 EDT: AEP called FE control room about AEP indication of Star-South Canton 345-kV line trip and reclosure. FE had no alarm or log of this line trip.

2E) 14:41 EDT: The primary FE control system server hosting the alarm function failed. Its applications and functions were passed over to a backup computer. FE's IT engineer was auto-paged.

2F) 14:54 EDT: The FE back-up computer failed and all functions that were running on it stopped. FE's IT engineer was auto-paged.

Failure of FE's Alarm System

Cause 2
Inadequate Situational Awareness

FE's computer SCADA alarm and logging software failed sometime shortly after 14:14 EDT (the last time that a valid alarm came in), after voltages had begun deteriorating but well before any of FE's lines began to contact trees and trip out. After that time, the FE control room consoles did not receive any further alarms, nor were there any alarms being printed or posted on the EMS's alarm logging facilities. Power system operators rely heavily on audible and on-screen alarms, plus alarm logs, to reveal any significant changes in their system's conditions. After 14:14 EDT on August 14, FE's operators were working under a significant handicap without these tools. However, they were in further jeopardy because they did not know that they were operating without alarms, so that they did not realize that system conditions were changing.

Alarms are a critical function of an EMS, and EMS-generated alarms are the fundamental means by which system operators identify events on the power system that need their attention. Without alarms, events indicating one or more significant system changes can occur but remain undetected by the operator. If an EMS's alarms are absent, but operators are aware of the situation and the remainder of the EMS's functions are intact, the operators can potentially continue to use the EMS to monitor and exercise control of their power system. In such circumstances, the operators would have to do so via repetitive, continuous manual scanning of numerous data and status points located within the multitude of individual displays available within their EMS. Further, it would be difficult for the operator to identify quickly the most relevant of the many screens available.

In the same way that an alarm system can inform operators about the failure of key grid facilities, it can also be set up to alarm them if the alarm system itself fails to perform properly. FE's EMS did not have such a notification system.

Although the alarm processing function of FE's EMS failed, the remainder of that system generally continued to collect valid real-time status information and measurements about FE's power system, and continued to have supervisory control over the FE system. The EMS also continued to send its normal and expected collection of information on to other monitoring points and authorities, including MISO and AEP. Thus these entities continued to receive accurate information about the status and condition of FE's power system after the time when FE's EMS alarms failed. FE's operators were unaware that in this situation they needed to manually and more closely monitor and interpret the SCADA information they were receiving. Continuing on in the belief that their system was satisfactory, lacking any alarms from their EMS to the contrary, and without visualization aids such as a dynamic map board or a projection of system topology, FE control room operators were subsequently surprised when they began receiving telephone calls from other locations and information sources—MISO, AEP, PJM, and FE field operations staff—who offered information on the status of FE's transmission facilities that conflicted with FE's system operators' understanding of the situation.

Recommendations
3, page 143, 22, page 159

Analysis of the alarm problem performed by FE suggests that the alarm process essentially "stalled" while processing an alarm event, such that the process began to run in a manner that failed to complete the processing of that alarm or

Alarms

System operators must keep a close and constant watch on the multitude of things occurring simultaneously on their power system. These include the system's load, the generation and supply resources to meet that load, available reserves, and measurements of critical power system states, such as the voltage levels on the lines. Because it is not humanly possible to watch and understand all these events and conditions simultaneously, Energy Management Systems use alarms to bring relevant information to operators' attention. The alarms draw on the information collected by the SCADA real-time monitoring system.

Alarms are designed to quickly and appropriately attract the power system operators' attention to events or developments of interest on the system. They do so using combinations of audible and visual signals, such as sounds at operators' control desks and symbol or color changes or animations on system monitors, displays, or map boards. EMS alarms for power systems are similar to the indicator lights or warning bell tones that a modern automobile uses to signal its driver, like the "door open" bell, an image of a headlight high beam, a "parking brake on" indicator, and the visual and audible alert when a gas tank is almost empty.

Power systems, like cars, use "status" alarms and "limit" alarms. A status alarm indicates the state of a monitored device. In power systems these are commonly used to indicate whether such items as switches or breakers are "open" or "closed" (off or on) when they should be otherwise, or whether they have changed condition since the last scan. These alarms should provide clear indication and notification to system operators of whether a given device is doing what they think it is, or what they want it to do—for instance, whether a given power line is connected to the system and moving power at a particular moment.

EMS limit alarms are designed to provide an indication to system operators when something important that is measured on a power system device—such as the voltage on a line or the amount of power flowing across it—is below or above pre-specified limits for using that device safely and efficiently. When a limit alarm activates, it provides an important early warning to the power system operator that elements of the system may need some adjustment to prevent damage to the system or to customer loads—like the "low fuel" or "high engine temperature" warnings in a car.

When FE's alarm system failed on August 14, its operators were running a complex power system without adequate indicators of when key elements of that system were reaching and passing the limits of safe operation—and without awareness that they were running the system without these alarms and should no longer assume that not getting alarms meant that system conditions were still safe and unchanging.

produce any other valid output (alarms). In the meantime, new inputs—system condition data that needed to be reviewed for possible alarms—built up in and then overflowed the process' input buffers.[9,10]

Loss of Remote EMS Terminals. Between 14:20 EDT and 14:25 EDT, some of FE's remote EMS terminals in substations ceased operation. FE has advised the investigation team that it believes this occurred because the data feeding into those terminals started "queuing" and overloading the terminals' buffers. FE's system operators did not learn about this failure until 14:36 EDT, when a technician at one of the sites noticed the terminal was not working after he came in on the 15:00 shift, and called the main control room to report the problem. As remote terminals failed, each triggered an automatic page to FE's Information Technology (IT) staff.[11] The investigation team has not determined why some terminals failed whereas others did not. Transcripts indicate that data links to the remote sites were down as well.[12]

EMS Server Failures. FE's EMS system includes several server nodes that perform the higher functions of the EMS. Although any one of them can host all of the functions, FE's normal system configuration is to have a number of host subsets of the applications, with one server remaining in a "hot-standby" mode as a backup to the others should any fail. At 14:41 EDT, the primary server hosting the EMS alarm processing application failed, due either to the stalling of the alarm application, "queuing" to the remote EMS terminals, or some combination of the two. Following preprogrammed instructions, the alarm system application and all other EMS software running on the first server automatically transferred ("failed-over") onto the back-up server. However, because the alarm application moved intact onto the backup while still stalled and ineffective, the backup server failed 13 minutes later, at 14:54 EDT. Accordingly, all of the EMS applications on these two servers stopped running.

Recommendation 22, page 159

Cause 2
Inadequate Situational Awareness

The concurrent loss of both EMS servers apparently caused several new problems for FE's EMS and the operators who used it. Tests run during FE's after-the-fact analysis of the alarm failure event indicate that a concurrent absence of these servers can significantly slow down the rate at which the EMS system puts new—or refreshes existing—displays on operators' computer consoles. Thus at times on August 14th, operators' screen refresh rates—the rate at which new information and displays are painted onto the computer screen, normally 1 to 3 seconds—slowed to as long as 59 seconds per screen. Since FE operators have numerous information screen options, and one or more screens are commonly "nested" as sub-screens to one or more top level screens, operators' ability to view, understand and operate their system through the EMS would have slowed to a frustrating crawl.[13] This situation may have occurred between 14:54 EDT and 15:08 EDT when both servers failed, and again between 15:46 EDT and 15:59 EDT while FE's IT personnel attempted to reboot both servers to remedy the alarm problem.

Loss of the first server caused an auto-page to be issued to alert FE's EMS IT support personnel to the problem. When the back-up server failed, it too sent an auto-page to FE's IT staff. They did not notify control room operators of the problem. At 15:08 EDT, IT staffers completed a "warm reboot" (restart) of the primary server. Startup diagnostics monitored during that reboot verified that the computer and all expected processes were running; accordingly, FE's IT staff believed that they had successfully restarted the node and all the processes it was hosting. However, although the server and its applications were again running, the alarm system remained frozen and non-functional, even on the restarted computer. The IT staff did not confirm that the alarm system was again working properly with the control room operators.

Recommendation 19, page 156

Another casualty of the loss of both servers was the Automatic Generation Control (AGC) function hosted on those computers. Loss of AGC meant that FE's operators could not run affiliated power plants on pre-set programs to respond automatically to meet FE's system load and interchange obligations. Although the AGC did not work from 14:54 EDT to 15:08 EDT and 15:46 EDT to 15:59 EDT (periods when both servers were down), this loss of function does not appear to have had an effect on the blackout.

Recommendation 22, page 159

Cause 2
Inadequate Situational Awareness

The concurrent loss of the EMS servers also caused the failure of FE's strip chart function. There are many strip charts in the FE Reliability Operator control room driven by the EMS computers, showing a variety of system conditions, including raw ACE (Area Control Error), FE system load, and Sammis-South Canton and South Canton-Star loading. These charts are visible in the reliability operator control room. The chart printers continued to scroll but because the underlying computer system was locked up the chart pens showed only the last valid measurement recorded, without any variation from that measurement as time progressed (i.e., the charts "flat-lined"). There is no indication that any operators noticed or reported the failed operation of the charts.[14] The few charts fed by direct analog telemetry, rather than the EMS system, showed primarily frequency data, and remained available throughout the afternoon of August 14. These yield little useful system information for operational purposes.

FE's Area Control Error (ACE), the primary control signal used to adjust generators and imports to match load obligations, did not function between 14:54 EDT and 15:08 EDT and later between 15:46 EDT and 15:59 EDT, when the two servers were down. This meant that generators were not controlled during these periods to meet FE's load and interchange obligations (except from 15:00 EDT to 15:09 EDT when control was switched to a backup controller). There were no apparent negative consequences from this failure. It has not been established how loss of the primary generation control signal was identified or if any discussions occurred with respect to the computer system's operational status.[15]

EMS System History. The EMS in service at FE's Ohio control center is a GE Harris (now GE Network Systems) XA21 system. It was initially brought into service in 1995. Other than the application of minor software fixes or patches typically encountered in the ongoing maintenance and support of such a system, the last major updates or revisions to this EMS were implemented in 1998. On August 14 the system was not running the most current release of the XA21 software. FE had

Who Saw What?

What data and tools did others have to monitor the conditions on the FE system?

Midwest ISO (MISO), reliability coordinator for FE

Alarms: MISO received indications of breaker trips in FE that registered in MISO's alarms; however, the alarms were missed. These alarms require a look-up to link the flagged breaker with the associated line or equipment and unless this line was specifically monitored, require another look-up to link the line to the monitored flowgate. MISO operators did not have the capability to click on the on-screen alarm indicator to display the underlying information.

Real Time Contingency Analysis (RTCA): The contingency analysis showed several hundred violations around 15:00 EDT. This included some FE violations, which MISO (FE's reliability coordinator) operators discussed with PJM (AEP's Reliability Coordinator).[a] Simulations developed for this investigation show that violations for a contingency would have occurred after the Harding-Chamberlin trip at 15:05 EDT. There is no indication that MISO addressed this issue. It is not known whether MISO identified the developing Sammis-Star problem.

Flowgate Monitoring Tool: While an inaccuracy has been identified with regard to this tool it still functioned with reasonable accuracy and prompted MISO to call FE to discuss the Hanna-Juniper line problem. It would not have identified problems south of Star since that was not part of the flowgate and thus not modeled in MISO's flowgate monitor.

AEP

Contingency Analysis: According to interviews,[b] AEP had contingency analysis that covered lines into Star. The AEP operator identified a problem for Star-South Canton overloads for a Sammis-Star line loss about 15:33 EDT and asked PJM to develop TLRs for this. However, due to the size of the requested TLR, this was not implemented before the line tripped out of service.

Alarms: Since a number of lines cross between AEP's and FE's systems, they had the ability at their respective end of each line to identify contingencies that would affect both. AEP initially noticed FE line problems with the first and subsequent trips of the Star-South Canton 345-kV line, and called FE three times between 14:35 EDT and 15:45 EDT to determine whether FE knew the cause of the outage.[c]

[a]"MISO Site Visit," Benbow interview.
[b]"AEP Site Visit," Ulrich interview.
[c]Example at 14:35, Channel 4; 15:19, Channel 4; 15:45, Channel 14 (FE transcripts).

decided well before August 14 to replace it with one from another vendor.

Recommendation 33, page 164

FE personnel told the investigation team that the alarm processing application had failed on occasions prior to August 14, leading to loss of the alarming of system conditions and events for FE's operators.[16] However, FE said that the mode and behavior of this particular failure event were both first time occurrences and ones which, at the time, FE's IT personnel neither recognized nor knew how to correct. FE staff told investigators that it was only during a post-outage support call with GE late on 14 August that FE and GE determined that the only available course of action to correct the alarm problem was a "cold reboot"[17] of FE's overall XA21 system. In interviews immediately after the blackout, FE IT personnel indicated that they discussed a cold reboot of the XA21 system with control room operators after they were told of the alarm problem at 15:42 EDT, but decided not to take such action because operators considered power system conditions precarious, were concerned about the length of time that the reboot might take to complete, and understood that a cold reboot would leave them with even less EMS functionality until it was completed.[18]

Clues to the EMS Problems. There is an entry in FE's western desk operator's log at 14:14 EDT referring to the loss of alarms, but it is not clear whether that entry was made at that time or subsequently, referring back to the last known alarm. There is no indication that the operator mentioned the problem to other control room staff and supervisors or to FE's IT staff.

Recommendation 26, page 161

The first clear hint to FE control room staff of any computer problems occurred at 14:19 EDT when a caller and an FE control room operator discussed the fact that three sub-transmission center dial-ups had failed.[19] At 14:25 EDT, a control room operator talked with a caller about the failure of these three remote EMS consoles.[20] The next hint came at 14:32 EDT, when FE scheduling staff spoke about having made schedule changes to update the EMS pages, but that the totals did not update.[21]

Cause 2
Inadequate Situational Awareness

Although FE's IT staff would have been aware that concurrent loss of its servers would mean the loss of alarm processing on the EMS, the investigation team has found no indication that the IT staff informed the control room staff either when they began work on the servers at 14:54 EDT, or when they completed the primary server restart at 15:08 EDT. At 15:42 EDT, the IT staff were first told of the alarm problem by a control room operator; FE has stated to investigators that their IT staff had been unaware before then that the alarm processing sub-system of the EMS was not working.

Without the EMS systems, the only remaining ways to monitor system conditions would have been through telephone calls and direct analog telemetry. FE control room personnel did not realize that alarm processing on their EMS was not working and, subsequently, did not monitor other available telemetry.

Cause 2
Inadequate Situational Awareness

During the afternoon of August 14, FE operators talked to their field personnel, MISO, PJM (concerning an adjoining system in PJM's reliability coordination region), adjoining systems (such as AEP), and customers. The FE operators received pertinent information from all these sources, but did not recognize the emerging problems from the clues offered. This pertinent information included calls such as that from FE's eastern control center asking about possible line trips, FE Perry nuclear plant calls regarding what looked like nearby line trips, AEP calling about their end of the Star-South Canton line tripping, and MISO and PJM calling about possible line overloads.

Recommendations 19, page 156; 26, page 161

Without a functioning alarm system, the FE control area operators failed to detect the tripping of electrical facilities essential to maintain the security of their control area. Unaware of the loss of alarms and a limited EMS, they made no alternate arrangements to monitor the system. When AEP identified the 14:27 EDT circuit trip and reclosure of the Star 345 kV line circuit breakers at AEP's South Canton substation, the FE operator dismissed the information as either not accurate or not relevant to his system, without following up on the discrepancy between the AEP event and the information from his own tools. There was no subsequent verification of conditions with the MISO reliability coordinator.

Only after AEP notified FE that a 345-kV circuit had tripped and locked out did the FE control area operator compare this information to actual breaker conditions. FE failed to inform its reliability coordinator and adjacent control areas when they became aware that system conditions had changed due to unscheduled equipment outages that might affect other control areas.

Recommendations
26, page 161; 30, page 163

Phase 3: Three FE 345-kV Transmission Line Failures and Many Phone Calls: 15:05 EDT to 15:57 EDT

Overview of This Phase

From 15:05:41 EDT to 15:41:35 EDT, three 345-kV lines failed with power flows at or below each transmission line's emergency rating. These line trips were not random. Rather, each was the result of a contact between a line and a tree that had grown so tall that, over a period of years, it encroached into the required clearance height for the line. As each line failed, its outage increased the loading on the remaining lines (Figure 5.5). As each of the transmission lines failed, and power flows shifted to other transmission paths, voltages on the rest of FE's system degraded further (Figure 5.6).

Key Phase 3 Events

3A) 15:05:41 EDT: Harding-Chamberlin 345-kV line tripped.

3B) 15:31-33 EDT: MISO called PJM to determine if PJM had seen the Stuart-Atlanta 345-kV line outage. PJM confirmed Stuart-Atlanta was out.

3C) 15:32:03 EDT: Hanna-Juniper 345-kV line tripped.

3D) 15:35 EDT: AEP asked PJM to begin work on a 350-MW TLR to relieve overloading on the Star-South Canton line, not knowing the Hanna-Juniper 345-kV line had already tripped at 15:32 EDT.

3E) 15:36 EDT: MISO called FE regarding post-contingency overload on Star-Juniper 345-kV line for the contingency loss of the Hanna-Juniper 345-kV line, unaware at the start of the call that Hanna-Juniper had already tripped.

3F) 15:41:33-41 EDT: Star-South Canton 345-kV tripped, reclosed, tripped again at 15:41:35 EDT and remained out of service, all while AEP and PJM were discussing TLR relief options (event 3D).

Transmission lines are designed with the expectation that they will sag lower when they become hotter. The transmission line gets hotter with heavier line loading and under higher ambient temperatures, so towers and conductors are designed to be tall enough and conductors pulled tightly enough to accommodate expected sagging and still meet safety requirements. On a summer day, conductor temperatures can rise from 60°C on mornings with average wind to 100°C with hot air temperatures and low wind conditions.

A short-circuit occurred on the Harding-Chamberlin 345-kV line due to a contact between the line conductor and a tree. This line failed with power flow at only 44% of its normal and emergency line rating. Incremental line current and temperature increases, escalated by the loss of Harding-Chamberlin, caused more sag on the Hanna-Juniper line, which contacted a tree and failed with power flow at 88% of its normal and emergency line rating. Star-South Canton

Figure 5.5. FirstEnergy 345-kV Line Flows

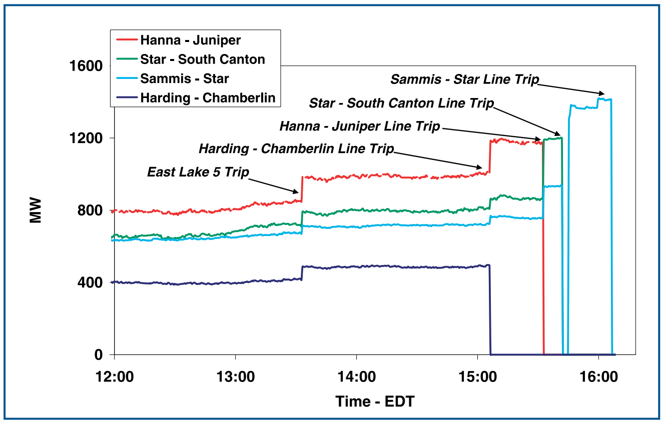


Figure 5.6. Voltages on FirstEnergy's 345-kV Lines: Impacts of Line Trips

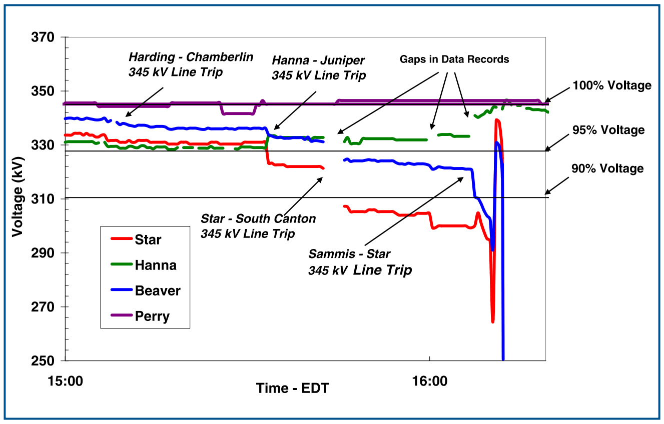
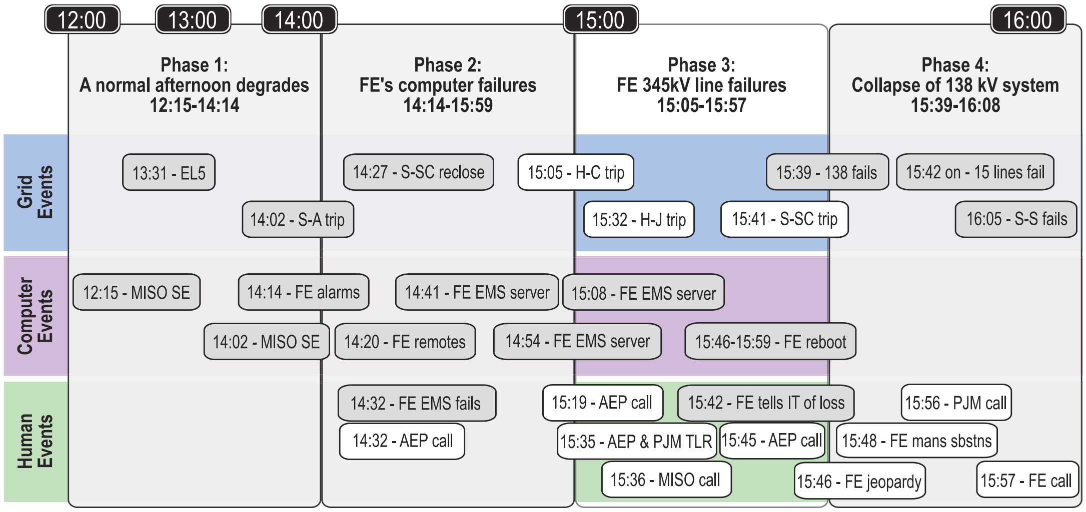


Figure 5.7. Timeline Phase 3



contacted a tree three times between 14:27:15 EDT and 15:41:33 EDT, opening and reclosing each time before finally locking out while loaded at 93% of its emergency rating at 15:41:35 EDT. Each of these three lines tripped not because of excessive sag due to overloading or high conductor temperature, but because it hit an overgrown, untrimmed tree.[22]

Cause 3
Inadequate Tree Trimming

Overgrown trees, as opposed to excessive conductor sag, caused each of these faults. While sag may have contributed to these events, these incidents occurred because the trees grew too tall and encroached into the space below the line which is intended to be clear of any objects, not because the lines sagged into short trees. Because the trees were so tall (as discussed below), each of these lines faulted under system conditions well within specified operating parameters. The investigation team found field evidence of tree contact at all three locations, including human observation of the Hanna-Juniper contact. Evidence outlined below confirms that contact with trees caused the short circuits to ground that caused each line to trip out on August 14.

To be sure that the evidence of tree/line contacts and tree remains found at each site was linked to the events of August 14, the team looked at whether these lines had any prior history of outages in preceding months or years that might have resulted in the burn marks, debarking, and other vegetative evidence of line contacts. The record establishes that there were no prior sustained outages known to be caused by trees for these lines in 2001, 2002, and 2003.[23]

Like most transmission owners, FE patrols its lines regularly, flying over each transmission line twice a year to check on the condition of the rights-of-way. Notes from fly-overs in 2001 and 2002 indicate that the examiners saw a significant number of trees and brush that needed clearing or

Line Ratings

A conductor's normal rating reflects how heavily the line can be loaded under routine operation and keep its internal temperature below a certain temperature (such as 90°C). A conductor's emergency rating is often set to allow higher-than-normal power flows, but to limit its internal temperature to a maximum temperature (such as 100°C) for no longer than a specified period, so that it does not sag too low or cause excessive damage to the conductor.

For three of the four 345-kV lines that failed, FE set the normal and emergency ratings at the same level. Many of FE's lines are limited by the maximum temperature capability of its terminal equipment, rather than by the maximum safe temperature for its conductors. In calculating summer emergency ampacity ratings for many of its lines, FE assumed 90°F (32°C) ambient air temperatures and 6.3 ft/sec (1.9 m/sec) wind speed,[a] which is a relatively high wind speed assumption for favorable wind cooling. Actual temperature on August 14 was 87°F (31°C) but wind speed at certain locations in the Akron area was somewhere between 0 and 2 ft/sec (0.6 m/sec) after 15:00 EDT that afternoon.

[a]FirstEnergy Transmission Planning Criteria (Revision 8), page 3.

trimming along many FE transmission lines. Notes from fly-overs in the spring of 2003 found fewer problems, suggesting that fly-overs do not allow effective identification of the distance between a tree and the line above it, and need to be supplemented with ground patrols.

Recommendations
16, page 154; 27, page 162

3A) FE's Harding-Chamberlin 345-kV Line Tripped: 15:05 EDT

At 15:05:41 EDT, FE's Harding-Chamberlin line (Figure 5.8) tripped and locked out while loaded at 44% of its normal and emergency rating. At this low loading, the line temperature would not exceed safe levels—even if still air meant there

Utility Vegetation Management: When Trees and Lines Contact

Vegetation management is critical to any utility company that maintains overhead energized lines. It is important and relevant to the August 14 events because electric power outages occur when trees, or portions of trees, grow up or fall into overhead electric power lines. While not all outages can be prevented (due to storms, heavy winds, etc.), some outages can be mitigated or prevented by managing the vegetation before it becomes a problem. When a tree contacts a power line it causes a short circuit, which is read by the line's relays as a ground fault. Direct physical contact is not necessary for a short circuit to occur. An electric arc can occur between a part of a tree and a nearby high-voltage conductor if a sufficient distance separating them is not maintained. Arcing distances vary based on such factors such as voltage and ambient wind and temperature conditions. Arcs can cause fires as well as short circuits and line outages.

Most utilities have right-of-way and easement agreements allowing them to clear and maintain vegetation as needed along their lines to provide safe and reliable electric power. Transmission easements generally give the utility a great deal of control over the landscape, with extensive rights to do whatever work is required to maintain the lines with adequate clearance through the control of vegetation. The three principal means of managing vegetation along a transmission right-of-way are pruning the limbs adjacent to the line clearance zone, removing vegetation completely by mowing or cutting, and using herbicides to retard or kill further growth. It is common to see more tree and brush removal using mechanical and chemical tools and relatively less pruning along transmission rights-of-way.

FE's easement agreements establish extensive rights regarding what can be pruned or removed in these transmission rights-of-way, including: "the right to erect, inspect, operate, replace, relocate, repair, patrol and permanently maintain upon, over, under and along the above described right of way across said premises all necessary structures, wires, cables and other usual fixtures and appurtenances used for or in connection with the transmission and distribution of electric current, including telephone and telegraph, and the right to trim, cut, remove or control by any other means at any and all times such trees, limbs and underbrush within or adjacent to said right of way as may interfere with or endanger said structures, wires or appurtenances, or their operations."[a]

FE uses a 5-year cycle for transmission line vegetation maintenance (i.e., it completes all required vegetation work within a 5-year period for all circuits). A 5-year cycle is consistent with industry practices, and it is common for transmission providers not to fully exercise their easement rights on transmission rights-of-way due to landowner or land manager opposition.

A detailed study prepared for this investigation, "Utility Vegetation Management Final Report," concludes that although FirstEnergy's vegetation management practices are within common or average industry practices, those common industry practices need significant improvement to assure greater transmission reliability.[b] The report further recommends that strict regulatory oversight and support will be required for utilities to improve and sustain needed improvements in their vegetation management programs.

NERC has no standards or requirements for vegetation management or transmission right-of-way clearances, nor for the determination of line ratings.

[a]Standard language in FE's right-of-way easement agreement.
[b]"Utility Vegetation Management Final Report," CN Utility Consulting, March 2004.

Cause 3
Inadequate Tree Trimming

was no wind cooling of the conductor—and the line would not sag excessively. The investigation team examined the relay data for this trip, identified the geographic location of the fault, and determined that the relay data match the classic "signature" pattern for a tree/line short circuit to ground fault. The field team found the remains of trees and brush at the fault location determined from the relay data. At this location, conductor height measured 46 feet 7 inches (14.20 meters), while the height of the felled tree measured 42 feet (12.80 meters); however, portions of the tree had been removed from the site. This means that while it is difficult to determine the exact height of the line contact, the measured height is a minimum and the actual contact was likely 3 to 4 feet (0.9 to 1.2 meters) higher than estimated here. Burn marks were observed 35 feet 8 inches (10.87 meters) up the tree, and the crown of this tree was at least 6 feet (1.83 meters) taller than the observed burn marks. The tree showed evidence of fault current damage.[24]

Recommendations
16, page 154; 27, page 162

When the Harding-Chamberlin line locked out, the loss of this 345-kV path caused the remaining three southern 345-kV lines into Cleveland to pick up more load, with Hanna-Juniper picking up the most. The Harding-Chamberlin outage also caused more power to flow through the underlying 138-kV system.

Cause 2
Inadequate Situational Awareness

MISO did not discover that Harding-Chamberlin had tripped until after the blackout, when MISO reviewed the breaker operation log that evening. FE indicates that it discovered the line was out while investigating system conditions in response to MISO's call at 15:36 EDT, when MISO told FE that MISO's flowgate monitoring tool showed a Star-Juniper line overload following a contingency loss of Hanna-Juniper;[25] however, the investigation team has found no evidence within the control room logs or transcripts to show that FE knew of the Harding-Chamberlin line failure until after the blackout.

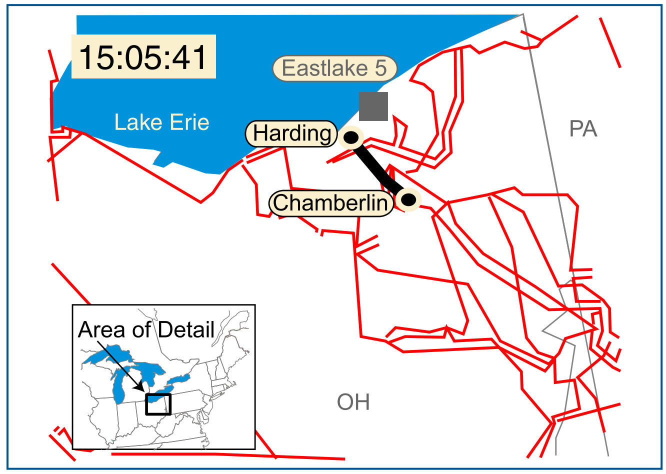
Recommendation
22, page 159

Cause 4
Inadequate RC Diagnostic Support

Harding-Chamberlin was not one of the flowgates that MISO monitored as a key transmission location, so the reliability coordinator was unaware when FE's first 345-kV line failed. Although MISO received SCADA input of the line's status change, this was presented to MISO operators as breaker status changes rather than a line failure. Because their EMS system topology processor had not yet been linked to recognize line failures, it did not connect the breaker information to the loss of a transmission line. Thus, MISO's operators did not recognize the Harding-Chamberlin trip as a significant contingency event and could not advise FE regarding the event or its consequences. Further, without its state estimator and associated contingency analyses, MISO was unable to identify potential overloads that would occur due to various line or equipment outages. Accordingly, when the Harding-Chamberlin 345-kV line tripped at 15:05 EDT, the state estimator did not produce results and could not predict an overload if the Hanna-Juniper 345-kV line were to fail.

Recommendation
30, page 163

Figure 5.8. Harding-Chamberlin 345-kV Line



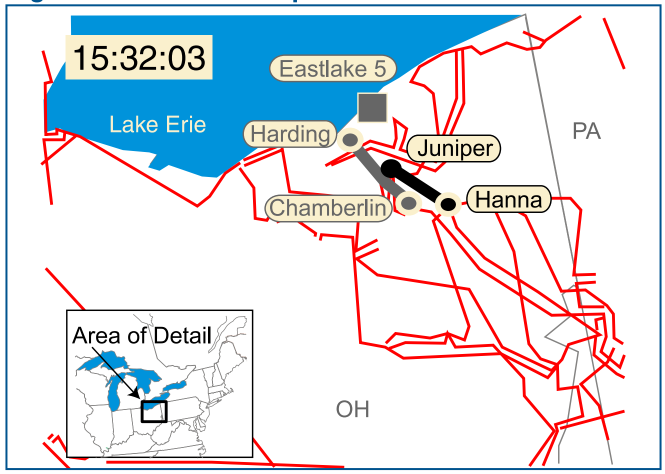
3C) FE's Hanna-Juniper 345-kV Line Tripped: 15:32 EDT

Cause 3
Inadequate Tree Trimming

At 15:32:03 EDT the Hanna-Juniper line (Figure 5.9) tripped and locked out. A tree-trimming crew was working nearby and observed the tree/line contact. The tree contact occurred on the south phase, which is lower than the center phase due to construction design. Although little evidence remained of the tree during the field team's visit in October, the team observed a tree stump 14 inches (35.5 cm) in diameter at its ground line and talked to an individual who witnessed the contact on August 14.[26] Photographs clearly indicate that the tree was of excessive height (Figure 5.10). Surrounding trees were 18 inches (45.7 cm) in diameter at ground line and 60 feet (18.3 meters) in height (not near lines). Other sites at this location had numerous (at least 20) trees in this right-of-way.

Hanna-Juniper was loaded at 88% of its normal and emergency rating when it tripped. With this line open, over 1,200 MVA of power flow had to find a new path to reach its load in Cleveland. Loading on the remaining two 345-kV lines increased, with Star-Juniper taking the bulk of the power. This caused Star-South Canton's loading to rise above its normal but within its emergency rating and pushed more power onto the 138-kV system. Flows west into Michigan decreased slightly and voltages declined somewhat in the Cleveland area.

Figure 5.9. Hanna-Juniper 345-kV Line

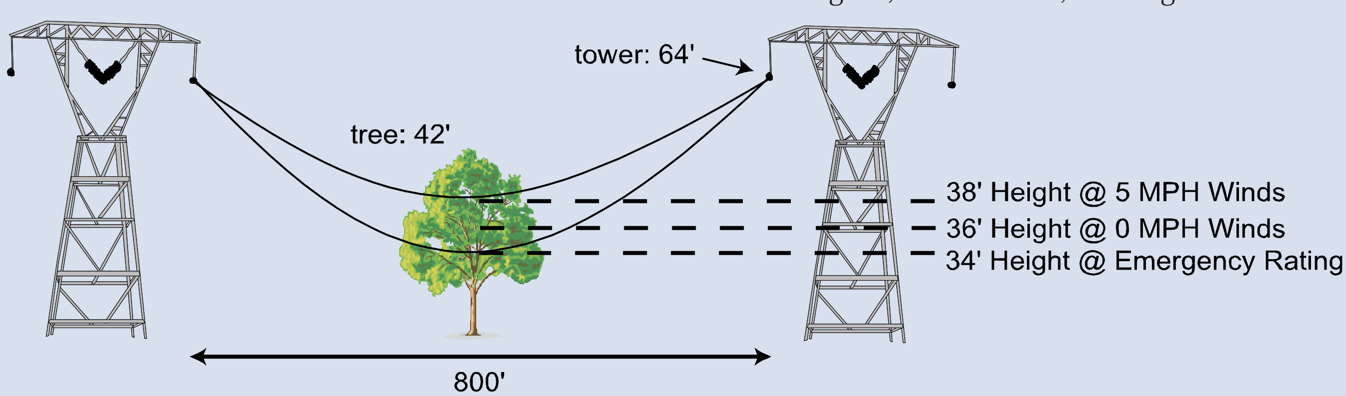


Why Did So Many Tree-to-Line Contacts Happen on August 14?

Tree-to-line contacts and resulting transmission outages are not unusual in the summer across much of North America. The phenomenon occurs because of a combination of events occurring particularly in late summer:

- Most tree growth occurs during the spring and summer months, so the later in the summer the taller the tree and the greater its potential to contact a nearby transmission line.
- As temperatures increase, customers use more air conditioning and load levels increase. Higher load levels increase flows on the transmission system, causing greater demands for both active power (MW) and reactive power (MVAr). Higher flow on a transmission line causes the line to heat up, and the hot line sags lower because the hot conductor metal expands. Most emergency line ratings are set to limit conductors' internal temperatures to no more than 100°C (212°F).
- As temperatures increase, ambient air temperatures provide less cooling for loaded transmission lines.
- Wind flows cool transmission lines by increasing the airflow of moving air across the line. On August 14 wind speeds at the Ohio Akron-Fulton airport averaged 5 knots (1.5 m/sec) at around 14:00 EDT, but by 15:00 EDT wind speeds had fallen to 2 knots (0.6 m/sec)—the wind speed commonly assumed in conductor design—or lower. With lower winds, the lines sagged further and closer to any tree limbs near the lines.

This combination of events on August 14 across much of Ohio and Indiana caused transmission lines to heat and sag. If a tree had grown into a power line's designed clearance area, then a tree/line contact was more likely, though not inevitable. An outage on one line would increase power flows on related lines, causing them to be loaded higher, heat further, and sag lower.



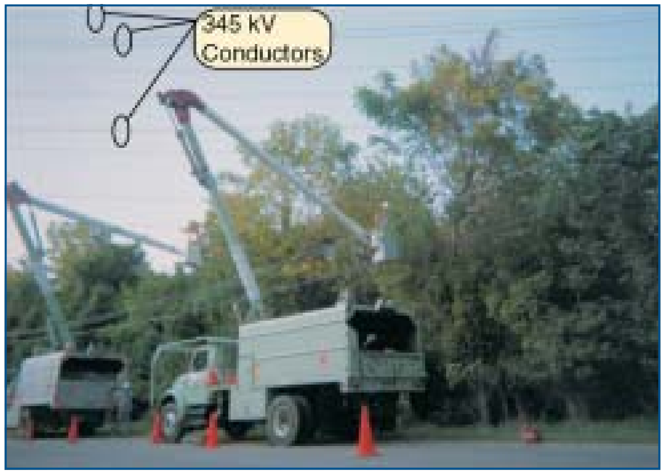
3D) AEP and PJM Begin Arranging a TLR for Star-South Canton: 15:35 EDT

Cause 4
Inadequate RC Diagnostic Support

Because its alarm system was not working, FE was not aware of the Harding-Chamberlin or Hanna-Juniper line trips. However, once MISO manually updated the state estimator model for the Stuart-Atlanta 345-kV line outage, the software successfully completed a state estimation and contingency analysis at 15:41 EDT. But this left a 36 minute period, from 15:05 EDT to 15:41 EDT, during which MISO did not recognize the consequences of the Hanna-Juniper loss, and FE operators knew neither of the line's loss nor its consequences. PJM and AEP recognized the overload on Star-South Canton, but had not expected it because their earlier contingency analysis did not examine enough lines within the FE system to foresee this result of the Hanna-Juniper contingency on top of the Harding-Chamberlin outage.

After AEP recognized the Star-South Canton overload, at 15:35 EDT AEP asked PJM to begin developing a 350 MW TLR to mitigate it. The TLR was to relieve the actual overload above normal rating then occurring on Star-South Canton, and prevent an overload above emergency rating on

Figure 5.10. Cause of the Hanna-Juniper Line Loss



This August 14 photo shows the tree that caused the loss of the Hanna-Juniper line (tallest tree in photo). Other 345-kV conductors and shield wires can be seen in the background. Photo by Nelson Tree.

Handling Emergencies by Shedding Load and Arranging TLRs

Transmission loading problems. Problems such as contingent overloads of normal ratings are typically handled by arranging Transmission Loading Relief (TLR) measures, which in most cases take effect as a schedule change 30 to 60 minutes after they are issued. Apart from a TLR level 6, TLRs are intended as a tool to prevent the system from being operated in an unreliable state,[a] and are not applicable in real-time emergency situations because it takes too long to implement reductions. Actual overloads and violations of stability limits need to be handled immediately under TLR level 4 or 6 by redispatching generation, system reconfiguration or tripping load. The dispatchers at FE, MISO and other control areas or reliability coordinators have authority—and under NERC operating policies, responsibility—to take such action, but the occasion to do so is relatively rare.

Lesser TLRs reduce scheduled transactions—non-firm first, then pro-rata between firm transactions, including flows that serve native load. When pre-contingent conditions are not solved with TLR levels 3 and 5, or conditions reach actual overloading or surpass stability limits, operators must use emergency generation redispatch and/or load-shedding under TLR level 6 to return to a secure state. After a secure state is reached, TLR level 3 and/or 5 can be initiated to relieve the emergency generation redispatch or load-shedding activation.

System operators and reliability coordinators, by NERC policy, have the responsibility and the authority to take actions up to and including emergency generation redispatch and shedding firm load to preserve system security. On August 14, because they either did not know or understand enough about system conditions at the time, system operators at FE, MISO, PJM, or AEP did not call for emergency actions.

Use of automatic procedures in voltage-related emergencies. There are few automatic safety nets in place in northern Ohio except for under-frequency load-shedding in some locations. In some utility systems in the U.S. Northeast, Ontario, and parts of the Western Interconnection, special protection systems or remedial action schemes, such as under-voltage load-shedding are used to shed load under defined severe contingency conditions similar to those that occurred in northern Ohio on August 14.

[a]"Northern MAPP/Northwestern Ontario Disturbance-June 25, 1998," NERC 1998 Disturbance Report, page 17.

that line if the Sammis-Star line were to fail. But when they began working on the TLR, neither AEP nor PJM realized that the Hanna-Juniper 345-kV line had already tripped at 15:32 EDT, further degrading system conditions. Since the great majority of TLRs are for cuts of 25 to 50 MW, a 350 MW TLR request was highly unusual and operators were attempting to confirm why so much relief was suddenly required before implementing the requested TLR. Less than ten minutes elapsed between the loss of Hanna-Juniper, the overload above the normal limits of Star-South Canton, and the Star-South Canton trip and lock-out.

Recommendations
6, page 147; 22, page 159; 30, page 163; 31, page 163

Cause 2
Inadequate Situational Awareness

Unfortunately, neither AEP nor PJM recognized that even a 350 MW TLR on the Star-South Canton line would have had little impact on the overload. Investigation team analysis using the Interchange Distribution Calculator (which was fully available on the afternoon of August 14) indicates that tagged transactions for the 15:00 EDT hour across Ohio had minimal impact on the overloaded lines. As discussed in Chapter 4, this analysis showed that after the loss of the Hanna-Juniper 345 kV line, Star-South Canton was loaded primarily with flows to serve native and network loads, delivering makeup energy for the loss of Eastlake 5, purchased from PJM (342 MW) and Ameren (126 MW). The only way that these high loadings could have been relieved would not have been from the redispatch that AEP requested, but rather from significant load-shedding by FE in the Cleveland area.

Cause 4
Inadequate RC Diagnostic Support

The primary tool MISO uses for assessing reliability on key flowgates (specified groupings of transmission lines or equipment that sometimes have less transfer capability than desired) is the flowgate monitoring tool. After the Harding-Chamberlin 345-kV line outage at 15:05 EDT, the flowgate monitoring tool produced incorrect (obsolete) results, because the outage was not reflected in the model. As a result, the tool assumed that Harding-Chamberlin was still available and did not predict an overload for loss of the Hanna-Juniper 345-kV line. When Hanna-Juniper tripped at 15:32 EDT, the resulting overload was detected by MISO's SCADA and set off alarms to MISO's system operators, who then phoned FE about it.[27] Because both MISO's state estimator and its flowgate monitoring tool were not working properly, MISO's ability to recognize FE's evolving contingency situation was impaired.

Recommendations
22, page 159; 30, page 163

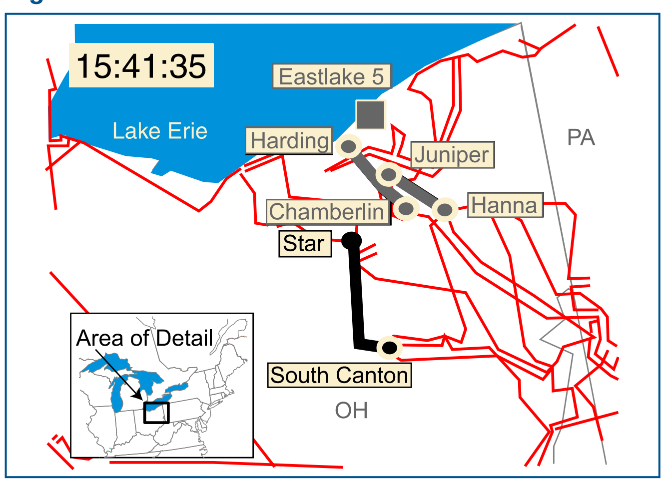
3F) Loss of the Star-South Canton 345-kV Line: 15:41 EDT

The Star-South Canton line (Figure 5.11) crosses the boundary between FE and AEP—each company owns the portion of the line and manages the right-of-way within its respective territory. The Star-South Canton line tripped and reclosed three times on the afternoon of August 14, first at 14:27:15 EDT while carrying less than 55% of its emergency rating (reclosing at both ends), then at 15:38:48 and again at 15:41:33 EDT. These multiple contacts had the effect of "electric tree-trimming," burning back the contacting limbs temporarily and allowing the line to carry more current until further sag in the still air caused the final contact and lock-out. At 15:41:35 EDT the line tripped and locked out at the Star substation, with power flow at 93% of its emergency rating. A short-circuit to ground occurred in each case.

Cause 3
Inadequate Tree Trimming

The investigation's field team inspected the right of way in the location indicated by the relay digital fault recorders, in the FE portion of the line. They found debris from trees and vegetation that had been felled. At this location the conductor height was 44 feet 9 inches (13.6 meters). The identifiable tree remains measured 30 feet (9.1 meters) in height, although the team could not verify the location of the stump, nor find all sections of the tree. A nearby cluster of trees showed significant fault damage, including charred limbs and de-barking from fault current. Further, topsoil in

Figure 5.11. Star-South Canton 345-kV Line



the area of the tree trunk was disturbed, discolored and broken up, a common indication of a higher magnitude fault or multiple faults. Analysis of another stump showed that a fourteen year-old tree had recently been removed from the middle of the right-of-way.[28]

Recommendations
16, page 154; 27, page 162

After the Star-South Canton line was lost, flows increased greatly on the 138-kV system toward Cleveland and area voltage levels began to degrade on the 138-kV and 69-kV system. At the same time, power flows increased on the Sammis-Star 345-kV line due to the 138-kV line trips—the only remaining paths into Cleveland from the south.

Cause 2
Inadequate Situational Awareness

FE's operators were not aware that the system was operating outside first contingency limits after the Harding-Chamberlin trip (for the possible loss of Hanna-Juniper or the Perry unit), because they did not conduct a contingency analysis.[29] The investigation team has not determined whether the system status information used by FE's state estimator and contingency analysis model was being accurately updated.

Recommendation
22, page159

Cause 1
Inadequate System Understanding

Load-Shed Analysis. The investigation team looked at whether it would have been possible to prevent the blackout by shedding load within the Cleveland-Akron area before the Star-South Canton 345 kV line tripped at 15:41 EDT. The team modeled the system assuming 500 MW of load shed within the Cleveland-Akron area before 15:41 EDT and found that this would have improved voltage at the Star bus from 91.7% up to 95.6%, pulling the line loading from 91 to 87% of its emergency ampere rating; an additional 500 MW of load would have had to be dropped to improve Star voltage to 96.6% and the line loading to 81% of its emergency ampere rating. But since the Star-South Canton line had already been compromised by the tree below it (which caused the first two trips and reclosures), and was about to trip from tree contact a third time, it is not clear that had such load shedding occurred, it would have prevented the ultimate trip and lock-out of the line. However, modeling indicates that this load shed would have prevented the subsequent tripping of the Sammis-Star line (see page 70).

Recommendations
8, page 147; 21, page 158

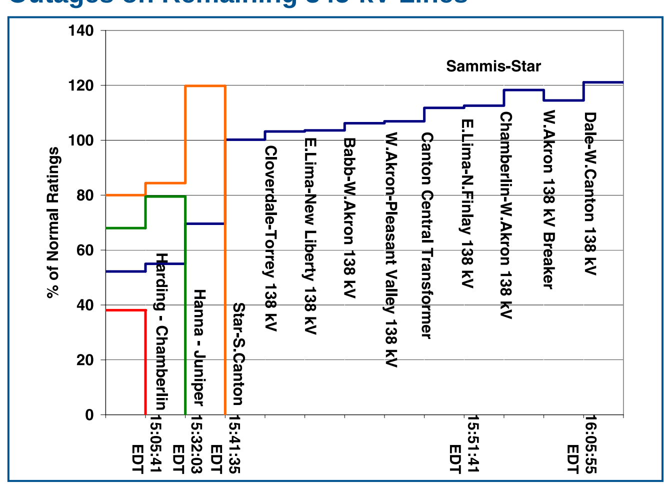
Cause 2
Inadequate Situational Awareness

System impacts of the 345-kV failures. According to extensive investigation team modeling, there were no contingency limit violations as of 15:05 EDT before the loss of the Harding-Chamberlin 345-kV line. Figure 5.12 shows the line loadings estimated by investigation team modeling as the 345-kV lines in northeast Ohio began to trip. Showing line loadings on the 345-kV lines as a percent of normal rating, it tracks how the loading on each line increased as each subsequent 345-kV and 138-kV line tripped out of service between 15:05 EDT (Harding-Chamberlin, the first line above to stair-step down) and 16:06 EDT (Dale-West Canton). As the graph shows, none of the 345- or 138-kV lines exceeded their normal ratings until after the combined trips of Harding-Chamberlin and Hanna-Juniper. But immediately after the second line was lost, Star-South Canton's loading jumped from an estimated 82% of normal to 120% of normal (which was still below its emergency rating) and remained at the 120% level for 10 minutes before tripping out. To the right, the graph shows the effects of the 138-kV line failures (discussed in the next phase) upon the two remaining 345-kV lines—i.e., Sammis-Star's loading increased steadily above 100% with each succeeding 138-kV line lost.

Following the loss of the Harding-Chamberlin 345-kV line at 15:05 EDT, contingency limit violations existed for:

- The Star-Juniper 345-kV line, whose loadings would exceed emergency limits if the Hanna-Juniper 345-kV line were lost; and

Figure 5.12. Cumulative Effects of Sequential Outages on Remaining 345-kV Lines



- The Hanna-Juniper and Harding-Juniper 345-kV lines, whose loadings would exceed emergency limits if the Perry generation unit (1,255 MW) were lost.

Operationally, once FE's system entered an N-1 contingency violation state, any facility loss beyond that pushed them farther into violation and into a more unreliable state. After loss of the Harding-Chamberlin line, to avoid violating NERC criteria, FE needed to reduce loading on these three lines within 30 minutes such that no single contingency would violate an emergency limit; that is, to restore the system to a reliable operating mode.

Phone Calls into the FE Control Room

Cause 2
Inadequate Situational Awareness

Beginning at 14:14 EDT when their EMS alarms failed, and until at least 15:42 EDT when they began to recognize their situation, FE operators did not understand how much of their system was being lost, and did not realize the degree to which their perception of their system was in error versus true system conditions, despite receiving clues via phone calls from AEP, PJM and MISO, and customers. The FE operators were not aware of line outages that occurred after the trip of Eastlake 5 at 13:31 EDT until approximately 15:45 EDT, although they were beginning to get external input describing aspects of the system's weakening condition. Since FE's operators were not aware and did not recognize events as they were occurring, they took no actions to return the system to a reliable state.

Recommendations
19, page 156; 26, page 161

A brief description follows of some of the calls FE operators received concerning system problems and their failure to recognize that the problem was on their system. For ease of presentation, this set of calls extends past the time of the 345-kV line trips into the time covered in the next phase, when the 138-kV system collapsed.

Following the first trip of the Star-South Canton 345-kV line at 14:27 EDT, AEP called FE at 14:32 EDT to discuss the trip and reclose of the line. AEP was aware of breaker operations at their end (South Canton) and asked about operations at FE's Star end. FE indicated they had seen nothing at their end of the line, but AEP reiterated that the trip occurred at 14:27 EDT and that the South Canton breakers had reclosed successfully.[30] There was an internal FE conversation about the AEP call at 14:51 EDT, expressing concern that they had not seen any indication of an operation, but lacking evidence within their control room, the FE operators did not pursue the issue.

At 15:19 EDT, AEP called FE back to confirm that the Star-South Canton trip had occurred and that AEP had a confirmed relay operation from the site. FE's operator restated that because they had received no trouble or alarms, they saw no problem. An AEP technician at the South Canton substation verified the trip. At 15:20 EDT, AEP decided to treat the South Canton digital fault recorder and relay target information as a "fluke," and checked the carrier relays to determine what the problem might be.[31]

At 15:35 EDT the FE control center received a call from the Mansfield 2 plant operator concerned about generator fault recorder triggers and excitation voltage spikes with an alarm for over-excitation, and a dispatcher called reporting a "bump" on their system. Soon after this call, FE's Reading, Pennsylvania control center called reporting that fault recorders in the Erie west and south areas had activated, wondering if something had happened in the Ashtabula-Perry area. The Perry nuclear plant operator called to report a "spike" on the unit's main transformer. When he went to look at the metering it was "still bouncing around pretty good. I've got it relay tripped up here . . . so I know something ain't right."[32]

Beginning at this time, the FE operators began to think that something was wrong, but did not recognize that it was on their system. "It's got to be in distribution, or something like that, or somebody else's problem . . . but I'm not showing anything."[33] Unlike many other transmission grid control rooms, FE's control center did not have a map board (which shows schematically all major lines and plants in the control area on the wall in front of the operators), which might have shown the location of significant line and facility outages within the control area.

Recommendation
22, page 159

At 15:36 EDT, MISO contacted FE regarding the post-contingency overload on Star-Juniper for the loss of the Hanna-Juniper 345-kV line.[34]

At 15:42 EDT, FE's western transmission operator informed FE's IT staff that the EMS system functionality was compromised. "Nothing seems to be updating on the computers . . . . We've had people calling and reporting trips and nothing seems to be updating in the event summary . . . I think we've got something seriously sick." This is the first evidence that a member of FE's control room staff recognized any aspect of their degraded EMS system. There is no indication that he informed any of the other operators at this moment. However, FE's IT staff discussed the subsequent EMS alarm corrective action with some control room staff shortly thereafter.

Also at 15:42 EDT, the Perry plant operator called back with more evidence of problems. "I'm still getting a lot of voltage spikes and swings on the generator . . . . I don't know how much longer we're going to survive."[35]

At 15:45 EDT, the tree trimming crew reported that they had witnessed a tree-caused fault on the Eastlake-Juniper 345-kV line; however, the actual fault was on the Hanna-Juniper 345-kV line in the same vicinity. This information added to the confusion in the FE control room, because the operator had indication of flow on the Eastlake-Juniper line.[36]

After the Star-South Canton 345-kV line tripped a third time and locked out at 15:41:35 EDT, AEP called FE at 15:45 EDT to discuss and inform them that they had additional lines that showed overload. FE recognized then that the Star breakers had tripped and remained open.[37]

At 15:46 EDT the Perry plant operator called the FE control room a third time to say that the unit was close to tripping off: "It's not looking good . . . . We ain't going to be here much longer and you're going to have a bigger problem."[38]

At 15:48 EDT, an FE transmission operator sent staff to man the Star substation, and then at 15:50 EDT, requested staffing at the regions, beginning with Beaver, then East Springfield.[39]

At 15:48 EDT, PJM called MISO to report the Star-South Canton trip, but the two reliability coordinators' measures of the resulting line flows on FE's Sammis-Star 345-kV line did not match, causing them to wonder whether the Star-South Canton 345-kV line had returned to service.[40]

At 15:56 EDT, because PJM was still concerned about the impact of the Star-South Canton trip, PJM called FE to report that Star-South Canton had tripped and that PJM thought FE's Sammis-Star line was in actual emergency limit overload.[41] FE could not confirm this overload. FE informed PJM that Hanna-Juniper was also out service. FE believed that the problems existed beyond their system. "AEP must have lost some major stuff."[42]

Emergency Action

For FirstEnergy, as with many utilities, emergency awareness is often focused on energy shortages. Utilities have plans to reduce loads under these circumstances to increasingly greater degrees. Tools include calling for contracted customer load reductions, then public appeals, voltage reductions, and finally shedding system load by cutting off interruptible and firm customers. FE has a plan for this that is updated yearly. While they can trip loads quickly where there is SCADA control of load breakers (although FE has few of these), from an energy point of view, the intent is to be able to regularly rotate what loads are not being served, which requires calling personnel out to switch the various groupings in and out. This event was not, however, a capacity or energy emergency or system instability, but an emergency due to transmission line overloads.

To handle an emergency effectively a dispatcher must first identify the emergency situation and then determine effective action. AEP identified potential contingency overloads at 15:36 EDT and called PJM even as Star-South Canton, one of the AEP/FE lines they were discussing, tripped and pushed FE's Sammis-Star 345-kV line to its emergency rating. Since they had been focused on the impact of a Sammis-Star loss overloading Star-South Canton, they recognized that a serious problem had arisen on the system for which they did not have a ready solution. Later, around 15:50 EDT, their conversation reflected emergency conditions (138-kV lines were tripping and several other lines overloaded) but they still found no practical way to mitigate these overloads across utility and reliability coordinator boundaries.

Recommendation 20, page 158

Cause 2
Inadequate Situational Awareness

At the control area level, FE remained unaware of the precarious condition its system was in, with key lines out of service, degrading voltages, and severe overloads on their remaining lines. Transcripts show that FE operators were aware of falling voltages and customer problems after loss of the Hanna-Juniper 345-kV line (at 15:32 EDT). They called out personnel to staff substations because they did not think they could see them with their data gathering tools. They were also talking to customers. But there is no indication that FE's operators clearly identified their situation as a possible emergency until around 15:45 EDT when the shift supervisor informed his manager that it looked as if they were losing the system; even then, although FE had grasped that its system was in trouble, it never officially declared that it was an emergency condition and that emergency or extraordinary action was needed.

FE's internal control room procedures and protocols did not prepare it adequately to identify and react to the August 14 emergency. Throughout the afternoon of August 14 there were many clues that FE had lost both its critical monitoring alarm functionality and that its transmission system's reliability was becoming progressively more compromised. However, FE did not fully piece these clues together until after it had already lost critical elements of its transmission system and only minutes before subsequent trips triggered the cascade phase of the blackout. The clues to a compromised EMS alarm system and transmission system came into the FE control room from FE customers, generators, AEP, MISO, and PJM. In spite of these clues, because of a number of related factors, FE failed to identify the emergency that it faced.

Recommendations
20, page 158; 22, page 159; 26, page 161

Cause 2
Inadequate Situational Awareness

The most critical factor delaying the assessment and synthesis of the clues was a lack of information sharing between the FE system operators. In interviews with the FE operators and analysis of phone transcripts, it is evident that rarely were any of the critical clues shared with fellow operators. This lack of information sharing can be attributed to:

Recommendation
26, page 161

1. Physical separation of operators (the reliability operator responsible for voltage schedules was across the hall from the transmission operators).

2. The lack of a shared electronic log (visible to all), as compared to FE's practice of separate hand-written logs.[43]

3. Lack of systematic procedures to brief incoming staff at shift change times.

4. Infrequent training of operators in emergency scenarios, identification and resolution of bad data, and the importance of sharing key information throughout the control room.

FE has specific written procedures and plans for dealing with resource deficiencies, voltage depressions, and overloads, and these include instructions to adjust generators and trip firm loads. After the loss of the Star-South Canton line, voltages were below limits, and there were severe line overloads. But FE did not follow any of these procedures on August 14, because FE did not know for most of that time that its system might need such treatment.

What training did the operators and reliability coordinators have for recognizing and responding to emergencies? FE relied upon on-the-job experience as training for its operators in handling the routine business of a normal day, but had never experienced a major disturbance and had no simulator training or formal preparation for recognizing and responding to emergencies. Although all affected FE and MISO operators were NERC-certified, NERC certification of operators addresses basic operational considerations but offers little insight into emergency operations issues. Neither group of operators had significant training, documentation, or actual experience for how to handle an emergency of this type and magnitude.

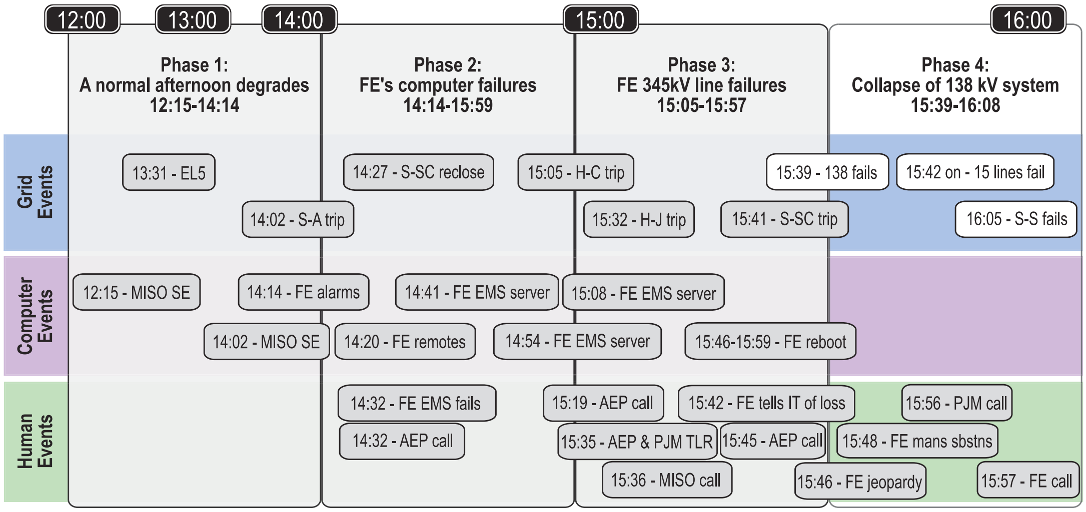
Recommendation
20, page 158

Cause 4
Inadequate RC Diagnostic Support

MISO was hindered because it lacked clear visibility, responsibility, authority, and ability to take the actions needed in this circumstance. MISO had interpretive and operational tools and a large amount of system data, but had a limited view of FE's system. In MISO's function as FE's reliability coordinator, its primary task was to initiate and implement TLRs, recognize and solve congestion problems in less dramatic reliability circumstances with longer solution time periods than those which existed on August 14, and provide assistance as requested.

Throughout August 14, most major elements of FE's EMS were working properly. The system was automatically transferring accurate real-time information about FE's system conditions to computers at AEP, MISO, and PJM. FE's operators did not believe the transmission line failures reported by AEP and MISO were real until 15:42 EDT, after FE conversations with the AEP and MISO control rooms and calls from FE IT staff to report the failure of their alarms. At that point in time, FE operators began to think that their system might be in jeopardy—but they did not act to restore any of the lost transmission lines, clearly alert their reliability coordinator or neighbors about their situation, or take other possible remedial measures (such as load- shedding) to stabilize their system.

Figure 5.13. Timeline Phase 4



Phase 4: 138-kV Transmission System Collapse in Northern Ohio: 15:39 to 16:08 EDT

Overview of This Phase

As each of FE's 345-kV lines in the Cleveland area tripped out, it increased loading and decreased voltage on the underlying 138-kV system serving Cleveland and Akron, pushing those lines into overload. Starting at 15:39 EDT, the first of an eventual sixteen 138-kV lines began to fail (Figure 5.13). Relay data indicate that each of these lines eventually ground faulted, which indicates that it sagged low enough to contact something below the line.

Figure 5.14 shows how actual voltages declined at key 138-kV buses as the 345- and 138-kV lines were lost. As these lines failed, the voltage drops caused a number of large industrial customers with voltage-sensitive equipment to go off-line automatically to protect their operations. As the 138-kV lines opened, they blacked out customers in Akron and the areas west and south of the city, ultimately dropping about 600 MW of load.

Key Phase 4 Events

Between 15:39 EDT and 15:58:47 EDT seven 138-kV lines tripped:

4A) 15:39:17 EDT: Pleasant Valley-West Akron 138-kV line tripped and reclosed at both ends after sagging into an underlying distribution line.

15:42:05 EDT: Pleasant Valley-West Akron 138-kV West line tripped and reclosed.

15:44:40 EDT: Pleasant Valley-West Akron 138-kV West line tripped and locked out.

4B) 15:42:49 EDT: Canton Central-Cloverdale 138-kV line tripped on fault and reclosed.

15:45:39 EDT: Canton Central-Cloverdale 138-kV line tripped on fault and locked out.

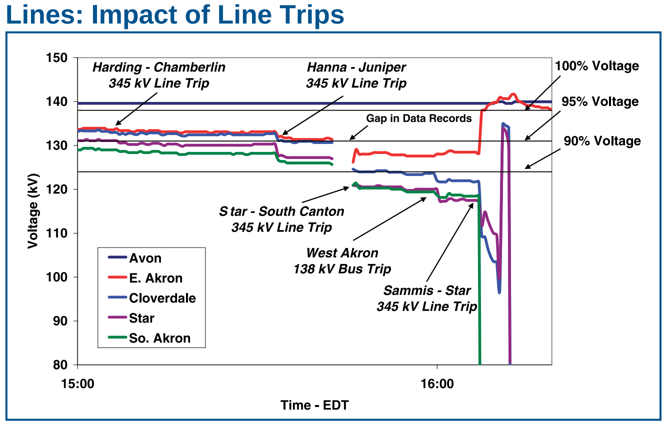
4C) 15:42:53 EDT: Cloverdale-Torrey 138-kV line tripped.

4D) 15:44:12 EDT: East Lima-New Liberty 138-kV line tripped from sagging into an underlying distribution line.

4E) 15:44:32 EDT: Babb-West Akron 138-kV line tripped on ground fault and locked out.

4F) 15:45:40 EDT: Canton Central 345/138 kV transformer tripped and locked out due to 138 kV circuit breaker operating multiple times,

Figure 5.14. Voltages on FirstEnergy's 138-kV Lines: Impact of Line Trips



which then opened the line to FE's Cloverdale station.

4G) 15:51:41 EDT: East Lima-N. Findlay 138-kV line tripped, likely due to sagging line, and reclosed at East Lima end only.

4H) 15:58:47 EDT: Chamberlin-West Akron 138-kV line tripped.

Note: 15:51:41 EDT: Fostoria Central-N. Findlay 138-kV line tripped and reclosed, but never locked out.

At 15:59:00 EDT, the loss of the West Akron bus tripped due to breaker failure, causing another five 138-kV lines to trip:

4I) 15:59:00 EDT: West Akron 138-kV bus tripped, and cleared bus section circuit breakers at West Akron 138 kV.

4J) 15:59:00 EDT: West Akron-Aetna 138-kV line opened.

4K) 15:59:00 EDT: Barberton 138-kV line opened at West Akron end only. West Akron-B18 138-kV tie breaker opened, affecting West Akron 138/12-kV transformers #3, 4 and 5 fed from Barberton.

4L) 15:59:00 EDT: West Akron-Granger-Stoney-Brunswick-West Medina opened.

4M) 15:59:00 EDT: West Akron-Pleasant Valley 138-kV East line (Q-22) opened.

4N) 15:59:00 EDT: West Akron-Rosemont-Pine-Wadsworth 138-kV line opened.

From 16:00 EDT to 16:08:59 EDT, four 138-kV lines tripped, and the Sammis-Star 345-kV line tripped due to high current and low voltage:

4O) 16:05:55 EDT: Dale-West Canton 138-kV line tripped due to sag into a tree, reclosed at West Canton only

4P) 16:05:57 EDT: Sammis-Star 345-kV line tripped

4Q) 16:06:02 EDT: Star-Urban 138-kV line tripped

4R) 16:06:09 EDT: Richland-Ridgeville-Napoleon-Stryker 138-kV line tripped on overload and locked out at all terminals

4S) 16:08:58 EDT: Ohio Central-Wooster 138-kV line tripped

Note: 16:08:55 EDT: East Wooster-South Canton 138-kV line tripped, but successful automatic reclosing restored this line.

4A-H) Pleasant Valley to Chamberlin-West Akron Line Outages

From 15:39 EDT to 15:58:47 EDT, seven 138-kV lines in northern Ohio tripped and locked out. At 15:45:41 EDT, Canton Central-Tidd 345-kV line tripped and reclosed at 15:46:29 EDT because Canton Central 345/138-kV CB "A1" operated multiple times, causing a low air pressure problem that inhibited circuit breaker tripping. This event forced the Canton Central 345/138-kV transformers to disconnect and remain out of service, further weakening the Canton-Akron area 138-kV transmission system. At 15:58:47 EDT the Chamberlin-West Akron 138-kV line tripped.

4I-N) West Akron Transformer Circuit Breaker Failure and Line Outages

At 15:59 EDT FE's West Akron 138-kV bus tripped due to a circuit breaker failure on West Akron transformer #1. This caused the five remaining 138-kV lines connected to the West Akron substation to open. The West Akron 138/12-kV transformers remained connected to the Barberton-West Akron 138-kV line, but power flow to West Akron 138/69-kV transformer #1 was interrupted.

4O-P) Dale-West Canton 138-kV and Sammis-Star 345-kV Lines Tripped

After the Cloverdale-Torrey line failed at 15:42 EDT, Dale-West Canton was the most heavily loaded line on FE's system. It held on, although heavily overloaded to 160 and 180% of normal ratings, until tripping at 16:05:55 EDT. The loss of this line had a significant effect on the area, and voltages dropped significantly. More power shifted back to the remaining 345-kV network, pushing Sammis-Star's loading above 120% of rating. Two seconds later, at 16:05:57 EDT, Sammis-Star tripped out. Unlike the previous three 345-kV lines, which tripped on short circuits to ground due to tree contacts, Sammis-Star tripped because its protective relays saw low apparent impedance (depressed voltage divided by abnormally high line current)—i.e., the relay reacted as if the high flow was due to a short circuit. Although three more 138-kV lines dropped quickly in Ohio following the Sammis-Star trip, loss of the Sammis-Star line marked the turning point at which system problems in northeast Ohio initiated a cascading blackout across the northeast United States and Ontario.

Losing the 138-kV Transmission Lines

The tripping of 138-kV transmission lines that began at 15:39 EDT occurred because the loss

Cause 1
Inadequate System Understanding

of the combination of the Harding-Chamberlin, Hanna-Juniper and Star-South Canton 345-kV lines overloaded the 138-kV system with electricity flowing north toward the Akron and Cleveland loads. Modeling indicates that the return of either the Hanna-Juniper or Chamberlin-Harding 345-kV lines would have diminished, but not alleviated, all of the 138-kV overloads. In theory, the return of both lines would have restored all the 138-kV lines to within their emergency ratings.

Cause 2
Inadequate Situational Awareness

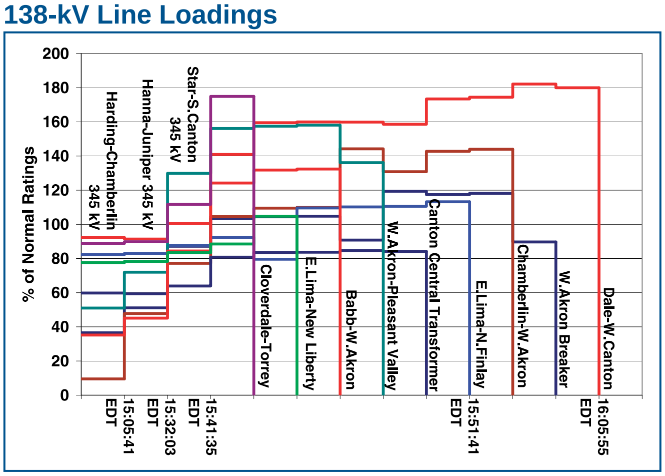
However, all three 345-kV lines had already been compromised due to tree contacts so it is unlikely that FE would have successfully restored either line had they known it had tripped out, and since Star-South Canton had already tripped and reclosed three times it is also unlikely that an operator knowing this would have trusted it to operate securely under emergency conditions. While generation redispatch scenarios alone would not have solved the overload problem, modeling indicates that shedding load in the Cleveland and Akron areas may have reduced most line loadings to within emergency range and helped stabilize the system. However, the amount of load shedding required grew rapidly as FE's system unraveled.

Preventing the Blackout with Load-Shedding

Cause 1
Inadequate System Understanding

The investigation team examined whether load shedding before the loss of the Sammis-Star 345-kV line at 16:05:57 EDT could have prevented this line loss. The team found that 1,500 MW of load would have had to be

Figure 5.15. Simulated Effect of Prior Outages on 138-kV Line Loadings



dropped within the Cleveland-Akron area to restore voltage at the Star bus from 90.8% (at 120% of normal and emergency ampere rating) up to 95.9% (at 101% of normal and emergency ampere rating).[44] The P-V and V-Q analysis reviewed in Chapter 4 indicated that 95% is the minimum operating voltage appropriate for 345-kV buses in the Cleveland-Akron area. The investigation team concluded that since the Sammis-Star 345 kV outage was the critical event leading to widespread cascading in Ohio and beyond, if manual or automatic load-shedding of 1,500 MW had occurred within the Cleveland-Akron area before that outage, the blackout could have been averted.

Recommendations
8, page 147; 21, page 158; 23, page 160

Loss of the Sammis-Star 345-kV Line

Figure 5.15, derived from investigation team modeling, shows how the power flows shifted across FE's 345- and key 138-kV northeast Ohio lines as the line failures progressed. All lines were loaded within normal limits after the Harding-Chamberlin lock-out, but after the Hanna-Juniper trip at 15:32 EDT, the Star-South Canton 345-kV line and three 138-kV lines jumped above normal loadings. After Star-South Canton locked out at 15:41 EDT within its emergency rating, five 138-kV and the Sammis-Star 345-kV lines were overloaded. From that point, as the graph shows, each subsequent line loss increased loadings on other lines, some loading to well over 150% of normal ratings before they failed. The Sammis-Star 345-kV line stayed in service until it tripped at 16:05:57 EDT.

FirstEnergy had no automatic load-shedding schemes in place, and did not attempt to begin manual load-shedding. As Chapters 4 and 5 have established, once Sammis-Star tripped, the possibility of averting the coming cascade by shedding load ended. Within 6 minutes of these overloads, extremely low voltages, big power swings and accelerated line tripping would cause separations and blackout within the Eastern Interconnection.

Recommendation
21, page 158

Endnotes

1 Investigation team field visit to FE 10/8/2003: Steve Morgan.

2 Investigation team field visit to FE, September 3, 2003, Hough interview: "When asked whether the voltages seemed unusual, he said that some sagging would be expected on a hot day, but on August 14th the voltages did seem unusually low." Spidle interview: "The voltages for the day were not particularly bad."

3 Manual of Operations, valid as of March 3, 2003, Process flowcharts: Voltage Control and Reactive Support – Plant and System Voltage Monitoring Under Normal Conditions.

4 14:13:18. Channel 16 - Sammis 1. 13:15:49 / Channel 16 – West Lorain (FE Reliability Operator (RO) says, "Thanks. We're starting to sag all over the system.") / 13:16:44. Channel 16 – Eastlake (talked to two operators) (RO says, "We got a way bigger load than we thought we would have." And "…So we're starting to sag all over the system.") / 13:20:22. Channel 16 – RO to "Berger" / 13:22:07. Channel 16 – "control room" RO says, "We're sagging all over the system. I need some help." / 13:23:24. Channel 16 – "Control room, Tom" / 13:24:38. Channel 16 – "Unit 9" / 13:26:04. Channel 16 – "Dave" / 13:28:40. Channel 16 "Troy Control." Also general note in RO Dispatch Log.

5 Example at 13:33:40, Channel 3, FE transcripts.

6 Investigation team field visit to MISO, Walsh and Seidu interviews.

7 FE had and ran a state estimator every 30 minutes. This served as a base from which to perform contingency analyses. FE's contingency analysis tool used SCADA and EMS inputs to identify any potential overloads that could result from various line or equipment outages. FE indicated that it has experienced problems with the automatic contingency analysis operation since the system was installed in 1995. As a result, FE operators or engineers ran contingency analysis manually rather than automatically, and were expected to do so when there were questions about the state of the system. Investigation team interviews of FE personnel indicate that the contingency analysis model was likely running but not consulted at any point in the afternoon of August 14.

8 After the Stuart-Atlanta line tripped, Dayton Power & Light did not immediately provide an update of a change in equipment availability using a standard form that posts the status change in the SDX (System Data Exchange, the NERC database which maintains real-time information on grid equipment status), which relays that notice to reliability coordinators and control areas. After its state estimator failed to solve properly, MISO checked the SDX to make sure that they had properly identified all available equipment and outages, but found no posting there regarding Stuart-Atlanta's outage.

9 Investigation team field visit, interviews with FE personnel on October 8-9, 2003.

10 DOE Site Visit to First Energy, September 3, 2003, Interview with David M. Elliott.

11 FE Report, "Investigation of FirstEnergy's Energy Management System Status on August 14, 2003," Bullet 1, Section 4.2.11.

12 Investigation team interviews with FE, October 8-9, 2003.

13 Investigation team field visit to FE, October 8-9, 2003: team was advised that FE had discovered this effect during post-event investigation and testing of the EMS. FE's report "Investigation of FirstEnergy's Energy Management System Status on August 14, 2003" also indicates that this finding was "verified using the strip charts from 8-14-03" (page 23), not that the investigation of this item was instigated by operator reports of such a failure.

14 There is a conversation between a Phil and a Tom that speaks of "flatlining" 15:01:33. Channel 15. There is no mention of AGC or generation control in the DOE Site Visit interviews with the reliability coordinator.

15 FE Report, "Investigation of FirstEnergy's Energy Management System Status on August 14, 2003."

16 Investigation team field visit to FE, October 8-9, 2003, Sanicky Interview: "From his experience, it is not unusual for alarms to fail. Often times, they may be slow to update or they may die completely. From his experience as a real-time operator, the fact that the alarms failed did not surprise him." Also from same document, Mike McDonald interview, "FE has previously had [servers] down at the same time. The big issue for them was that they were not receiving new alarms."

17 A "cold" reboot of the XA21 system is one in which all nodes (computers, consoles, etc.) of the system are shut down and then restarted. Alternatively, a given XA21 node can be "warm" rebooted wherein only that node is shut down and restarted, or restarted from a shutdown state. A cold reboot will take significantly longer to perform than a warm one. Also during a cold reboot much more of the system is unavailable for use by the control room operators for visibility or control over the power system. Warm reboots are not uncommon, whereas cold reboots are rare. All reboots undertaken by FE's IT EMSS support personnel on August 14 were warm reboots.

18 The cold reboot was done in the early morning of 15 August and corrected the alarm problem as hoped.

19 Example at 14:19, Channel l4, FE transcripts.

20 Example at 14:25, Channel 8, FE transcripts.

21 Example at 14:32, Channel 15, FE transcripts.

22 "Interim Report, Utility Vegetation Management," U.S.-Canada Joint Outage Investigation Task Force, Vegetation Management Program Review, October 2003, page 7.

23 Investigation team transcript, meeting on September 9, 2003, comments by Mr. Steve Morgan, Vice President Electric Operations:

Mr. Morgan: The sustained outage history for these lines, 2001, 2002, 2003, up until the event, Chamberlin-Harding had zero operations for those two-and-a-half years. And Hanna-Juniper had six operations in 2001, ranging from four minutes to maximum of 34 minutes. Two were unknown, one was lightning, one was a relay failure, and two were really relay scheme mis-operations. They're category other. And typically, that—I don't know what this is particular to operations, that typically occurs when there is a mis-operation.

Star-South Canton had no operations in that same period of time, two-and-a-half years. No sustained outages. And Sammis-Star, the line we haven't talked about, also no sustained outages during that two-and-a-half year period. So is it normal? No. But 345 lines do operate, so it's not unknown.

24 "Utility Vegetation Management Final Report," CN Utility Consulting, March 2004, page 32.

25 "FE MISO Findings," page 11.

26 FE was conducting right-of-way vegetation maintenance on a 5-year cycle, and the tree crew at Hanna-Juniper was three spans away, clearing vegetation near the line, when the contact occurred on August 14. Investigation team 9/9/03 meeting transcript, and investigation field team discussion with the tree-trimming crew foreman.

27 Based on "FE MISO Findings" document, page 11.

28 "Interim Report, Utility Vegetation Management," US-Canada Joint Outage Task Force, Vegetation Management Program Review, October 2003, page 6.

29 Investigation team September 9, 2003 meeting transcripts, Mr. Steve Morgan, First Energy Vice President, Electric System Operations:

Mr. Benjamin: Steve, just to make sure that I'm understanding it correctly, you had indicated that once after Hanna-Juniper relayed out, there wasn't really a problem with voltage on the system until Star-S. Canton operated. But were the system operators aware that when Hanna-Juniper was out, that if Star-S. Canton did trip, they would be outside of operating limits?

Mr. Morgan: I think the answer to that question would have required a contingency analysis to be done probably on demand for that operation. It doesn't appear to me that a contingency analysis, and certainly not a demand contingency analysis, could have been run in that period of time. Other than experience, I don't know that they would have been able to answer that question. And what I know of the record right now is that it doesn't appear that they ran contingency analysis on demand.

Mr. Benjamin: Could they have done that?

Mr. Morgan: Yeah, presumably they could have.

Mr. Benjamin: You have all the tools to do that?

Mr. Morgan: They have all the tools and all the information is there. And if the State Estimator is successful in solving, and all the data is updated, yeah, they could have. I would say in addition to those tools, they also have access to the planning load flow model that can actually run the same—full load of the model if they want to.

[30] Example synchronized at 14:32 (from 13:32) #18 041 TDC-E2 283.wav, AEP transcripts.

[31] Example synchronized at 14:19 #2 020 TDC-E1 266.wav, AEP transcripts.

[32] Example at 15:36 Channel 8, FE transcripts.

[33] Example at 15:41:30 Channel 3, FE transcripts.

[34] Example synchronized at 15:36 (from 14:43) Channel 20, MISO transcripts.

[35] Example at 15:42:49, Channel 8, FE transcripts.

[36] Example at 15:46:00, Channel 8 FE transcripts.

[37] Example at 15:45:18, Channel 4, FE transcripts.

[38] Example at 15:46:00, Channel 8 FE transcripts.

[39] Example at 15:50:15, Channel 12 FE transcripts.

[40] Example synchronized at 15:48 (from 14:55), channel 22, MISO transcripts.

[41] Example at 15:56:00, Channel 31, FE transcripts.

[42] FE Transcripts 15:45:18 on Channel 4 and 15:56:49 on Channel 31.

[43] The operator logs from FE's Ohio control center indicate that the west desk operator knew of the alarm system failure at 14:14, but that the east desk operator first knew of this development at 15:45. These entries may have been entered after the times noted, however.

[44] The investigation team determined that FE was using a different set of line ratings for Sammis-Star than those being used in the MISO and PJM reliability coordinator calculations or by its neighbor AEP. Specifically, FE was operating Sammis-Star assuming that the 345-kV line was rated for summer normal use at 1,310 MVA, with a summer emergency limit rating of 1,310 MVA. In contrast, MISO, PJM and AEP were using a more conservative rating of 950 MVA normal and 1,076 MVA emergency for this line. The facility owner (in this case FE) is the entity which provides the line rating; when and why the ratings were changed and not communicated to all concerned parties has not been determined.

6. The Cascade Stage of the Blackout

Chapter 5 described how uncorrected problems in northern Ohio developed to 16:05:57 EDT, the last point at which a cascade of line trips could have been averted. However, the Task Force's investigation also sought to understand how and why the cascade spread and stopped as it did. As detailed below, the investigation determined the sequence of events in the cascade, and how and why it spread, and how it stopped in each general geographic area.

Based on the investigation to date, the investigation team concludes that the cascade spread beyond Ohio and caused such a widespread blackout for three principal reasons. First, the loss of the Sammis-Star 345-kV line in Ohio, following the loss of other transmission lines and weak voltages within Ohio, triggered many subsequent line trips. Second, many of the key lines which tripped between 16:05:57 and 16:10:38 EDT operated on zone 3 impedance relays (or zone 2 relays set to operate like zone 3s) which responded to overloads rather than true faults on the grid. The speed at which they tripped spread the reach and accelerated the spread of the cascade beyond the Cleveland-Akron area. Third, the evidence collected indicates that the relay protection settings for the transmission lines, generators and under-frequency load-shedding in the northeast may not be entirely appropriate and are certainly not coordinated and integrated to reduce the likelihood and consequences of a cascade—nor were they intended to do so. These issues are discussed in depth below.

This analysis is based on close examination of the events in the cascade, supplemented by complex, detailed mathematical modeling of the electrical phenomena that occurred. At the completion of this report, the modeling had progressed through 16:10:40 EDT, and was continuing. Thus this chapter is informed and validated by modeling (explained below) up until that time. Explanations after that time reflect the investigation team's best hypotheses given the available data, and may be confirmed or modified when the modeling is complete. However, simulation of these events is so complex that it may be impossible to ever completely prove these or other theories about the fast-moving events of August 14. Final modeling results will be published by NERC as a technical report in several months.

Why Does a Blackout Cascade?

Major blackouts are rare, and no two blackout scenarios are the same. The initiating events will vary, including human actions or inactions, system topology, and load/generation balances. Other factors that will vary include the distance between generating stations and major load centers, voltage profiles across the grid, and the types and settings of protective relays in use.

Some wide-area blackouts start with short circuits (faults) on several transmission lines in short succession—sometimes resulting from natural causes such as lightning or wind or, as on August 14, resulting from inadequate tree management in right-of-way areas. A fault causes a high current and low voltage on the line containing the fault. A protective relay for that line detects the high current and low voltage and quickly trips the circuit breakers to isolate that line from the rest of the power system.

A cascade is a dynamic phenomenon that cannot be stopped by human intervention once started. It occurs when there is a sequential tripping of numerous transmission lines and generators in a widening geographic area. A cascade can be triggered by just a few initiating events, as was seen on August 14. Power swings and voltage fluctuations caused by these initial events can cause other lines to detect high currents and low voltages that appear to be faults, even if faults do not actually exist on those other lines. Generators are tripped off during a cascade to protect them from severe power and voltage swings. Protective relay systems work well to protect lines and generators from damage and to isolate them from the system under normal and abnormal system conditions.

But when power system operating and design criteria are violated because several outages occur simultaneously, commonly used protective relays that measure low voltage and high current cannot distinguish between the currents and voltages seen in a system cascade from those caused by a fault. This leads to more and more lines and generators being tripped, widening the blackout area.

How Did the Cascade Evolve on August 14?

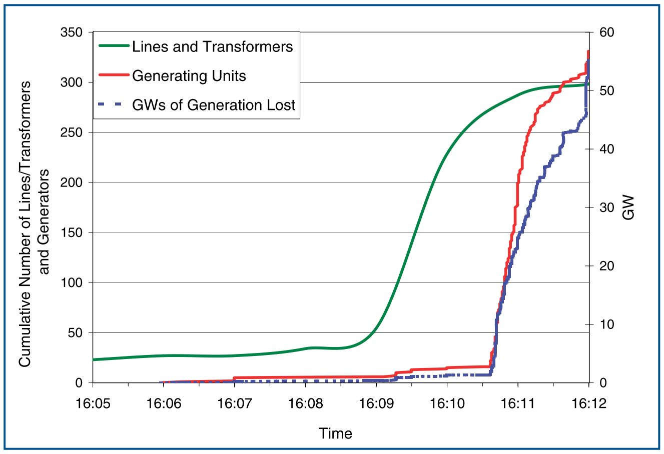
A series of line outages in northeast Ohio starting at 15:05 EDT caused heavy loadings on parallel circuits, leading to the trip and lock-out of FE's Sammis-Star 345-kV line at 16:05:57 Eastern Daylight Time. This was the event that triggered a cascade of interruptions on the high voltage system, causing electrical fluctuations and facility trips such that within seven minutes the blackout rippled from the Cleveland-Akron area across much of the northeast United States and Canada. By 16:13 EDT, more than 508 generating units at 265 power plants had been lost, and tens of millions of people in the United States and Canada were without electric power.

The events in the cascade started relatively slowly. Figure 6.1 illustrates how the number of lines and generation lost stayed relatively low during the Ohio phase of the blackout, but then picked up speed after 16:08:59 EDT. The cascade was complete only three minutes later.

Chapter 5 described the four phases that led to the initiation of the cascade at about 16:06 EDT. After 16:06 EDT, the cascade evolved in three distinct phases:

- **Phase 5.** The collapse of FE's transmission system induced unplanned shifts of power across the region. Shortly before the collapse, large (but normal) electricity flows were moving across FE's system from generators in the south (Tennessee and Kentucky) and west (Illinois and Missouri) to load centers in northern Ohio, eastern Michigan, and Ontario. A series of lines within northern Ohio tripped under the high

Figure 6.1. Rate of Line and Generator Trips During the Cascade



Impedance Relays

The most common protective device for transmission lines is the impedance (Z) relay (also known as a distance relay). It detects changes in currents (I) and voltages (V) to determine the apparent impedance ($Z=V/I$) of the line. A relay is installed at each end of a transmission line. Each relay is actually three relays within one, with each element looking at a particular "zone" or length of the line being protected.

- The first zone looks for faults over 80% of the line next to the relay, with no time delay before the trip.
- The second zone is set to look at the entire line and slightly beyond the end of the line with a slight time delay. The slight delay on the zone 2 relay is useful when a fault occurs near one end of the line. The zone 1 relay near that end operates quickly to trip the circuit breakers on that end. However, the zone 1 relay on the other end may not be able to tell if the fault is just inside the line or just beyond the line. In this case, the zone 2 relay on the far end trips the breakers after a short delay, after the zone 1 relay near the fault opens the line on that end first.
- The third zone is slower acting and looks for line faults and faults well beyond the length of the line. It can be thought of as a remote relay or breaker backup, but should not trip the breakers under typical emergency conditions.

An impedance relay operates when the apparent impedance, as measured by the current and voltage seen by the relay, falls within any one of the operating zones for the appropriate amount of time for that zone. The relay will trip and cause circuit breakers to operate and isolate the line. All three relay zone operations protect lines from faults and may trip from apparent faults caused by large swings in voltages and currents.

loads, hastened by the impact of Zone 3 impedance relays. This caused a series of shifts in power flows and loadings, but the grid stabilized after each.

- **Phase 6.** After 16:10:36 EDT, the power surges resulting from the FE system failures caused lines in neighboring areas to see overloads that caused impedance relays to operate. The result was a wave of line trips through western Ohio that separated AEP from FE. Then the line trips progressed northward into Michigan separating western and eastern Michigan, causing a power flow reversal within Michigan toward Cleveland. Many of these line trips were from Zone 3 impedance relay actions that accelerated the speed of the line trips and reduced the potential time in which grid operators might have identified the growing problem and acted constructively to contain it.

  With paths cut from the west, a massive power surge flowed from PJM into New York and Ontario in a counter-clockwise flow around Lake Erie to serve the load still connected in eastern Michigan and northern Ohio. Relays on the lines between PJM and New York saw this massive power surge as faults and tripped those lines. Ontario's east-west tie line also became overloaded and tripped, leaving northwest Ontario connected to Manitoba and Minnesota. The entire northeastern United States and eastern Ontario then became a large electrical island separated from the rest of the Eastern Interconnection. This large area, which had been importing power prior to the cascade, quickly became unstable after 16:10:38 as there was not sufficient generation on-line within the island to meet electricity demand. Systems to the south and west of the split, such as PJM, AEP and others further away, remained intact and were mostly unaffected by the outage. Once the northeast split from the rest of the Eastern Interconnection, the cascade was isolated.

- **Phase 7.** In the final phase, after 16:10:46 EDT, the large electrical island in the northeast had less generation than load, and was unstable with large power surges and swings in frequency and voltage. As a result, many lines and generators across the disturbance area tripped, breaking the area into several electrical islands. Generation and load within these smaller islands was often unbalanced, leading to further tripping of lines and generating units until equilibrium was established in each island.

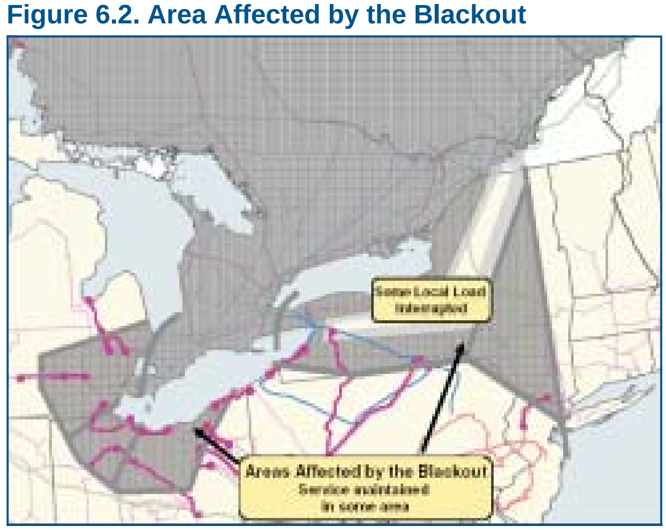
  Although much of the disturbance area was fully blacked out in this process, some islands were able to reach equilibrium without total loss of service. For example, the island consisting of most of New England and the Maritime Provinces stabilized and generation and load returned to balance. Another island consisted of load in western New York and a small portion of Ontario, supported by some New York generation, the large Beck and Saunders plants in Ontario, and the 765-kV interconnection to Québec. This island survived but some other areas with large load centers within the island collapsed into a blackout condition (Figure 6.2).

What Stopped the August 14 Blackout from Cascading Further?

The investigation concluded that a combination of the following factors determined where and when the cascade stopped spreading:

- The effects of a disturbance travel over power lines and become damped the further they are from the initial point, much like the ripple from a stone thrown in a pond. Thus, the voltage and current swings seen by relays on lines farther away from the initial disturbance are not as severe, and at some point they are no longer sufficient to cause lines to trip.
- Higher voltage lines and more densely networked lines, such as the 500-kV system in PJM and the 765-kV system in AEP, are better able to absorb voltage and current swings and thus serve as a barrier to the spread of a cascade. As seen in Phase 6, the cascade progressed into western Ohio and then northward through Michigan through the areas that had the fewest transmission lines. Because there were fewer

Figure 6.2. Area Affected by the Blackout



System Oscillations, Stable, Transient, and Dynamic Conditions

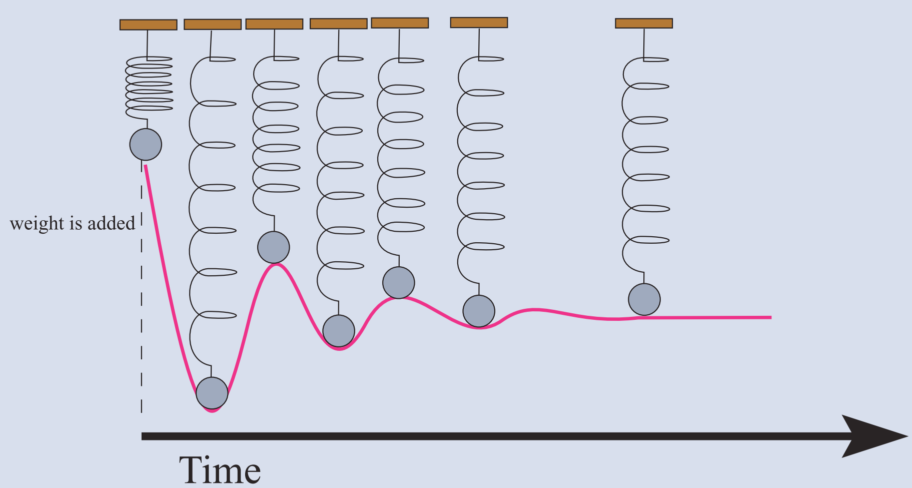
The electric power system constantly experiences small power oscillations that do not lead to system instability. They occur as generator rotors accelerate or slow down while rebalancing electrical output power to mechanical input power, to respond to changes in load or network conditions. These oscillations are observable in the power flow on transmission lines that link generation to load or in the tie lines that link different regions of the system together. But with a disturbance to the network, the oscillations can become more severe, even to the point where flows become progressively so great that protective relays trip the connecting lines. If the lines connecting different electrical regions separate, each region will find its own frequency, depending on the load to generation balance at the time of separation.

Oscillations that grow in amplitude are called unstable oscillations. Such oscillations, once initiated, cause power to flow back and forth across the system like water sloshing in a rocking tub.

In a stable electric system, if a disturbance such as a fault occurs, the system will readjust and rebalance within a few seconds after the fault clears. If a fault occurs, protective relays can trip in less than 0.1 second. If the system recovers and rebalances within less than 3 seconds, with the possible loss of only the faulted element and a few generators in the area around the fault, then that condition is termed "transiently stable." If the system takes from 3 to 30 seconds to recover and stabilize, it is "dynamically stable." But in rare cases when a disturbance occurs, the system may appear to rebalance quickly, but it then over-shoots and the oscillations can grow, causing widespread instability that spreads in terms of both the magnitude of the oscillations and in geographic scope. This can occur in a system that is heavily loaded, causing the electrical distance (apparent impedance) between generators to be longer, making it more difficult to keep the machine angles and speeds synchronized. In a system that is well damped, the oscillations will settle out quickly and return to a steady balance. If the oscillation continues over time, neither growing nor subsiding, it is a poorly damped system.

The illustration below, of a weight hung on a spring balance, illustrates a system which oscillates over several cycles to return to balance. A critical point to observe is that in the process of hunting for its balance point, the spring overshoots the true weight and balance point of the spring and weight combined, and must cycle through a series of exaggerated overshoots and underweight rebounds before settling down to rest at its true balance point. The same process occurs on an electric system, as can be observed in this chapter.

If a system is in transient instability, the oscillations following a disturbance will grow in magnitude rather than settle out, and it will be unable to readjust to a stable, steady state. This is what happened to the area that blacked out on August 14, 2003.



lines, each line absorbed more of the power and voltage surges and was more vulnerable to tripping. A similar effect was seen toward the east as the lines between New York and Pennsylvania, and eventually northern New Jersey tripped. The cascade of transmission line outages became contained after the northeast United States and Ontario were completely separated from the rest of the Eastern Interconnection and no more power flows were possible into the northeast (except the DC ties from Québec, which continued to supply power to western New York and New England).

- Line trips isolated some areas from the portion of the grid that was experiencing instability. Many of these areas retained sufficient on-line generation or the capacity to import power from other parts of the grid, unaffected by the surges or instability, to meet demand. As the cascade progressed, and more generators and lines tripped off to protect themselves from severe damage, some areas completely separated from the unstable part of the Eastern Interconnection. In many of these areas there was sufficient generation to match load and stabilize the system. After the large island was formed in the northeast, symptoms of frequency and voltage decay emerged. In some parts of the northeast, the system became too unstable and shut itself down. In other parts, there was sufficient generation, coupled with fast-acting automatic load shedding, to stabilize frequency and voltage. In this manner, most of New England and the Maritime Provinces remained energized. Approximately half of the generation and load remained on in western New York, aided by generation in southern Ontario that split and stayed with western New York. There were other smaller isolated pockets of load and generation that were able to achieve equilibrium and remain energized.

Phase 5: 345-kV Transmission System Cascade in Northern Ohio and South-Central Michigan

Overview of This Phase

After the loss of FE's Sammis-Star 345-kV line and the underlying 138-kV system, there were no large capacity transmission lines left from the south to support the significant amount of load in northern Ohio (Figure 6.3). This overloaded the transmission paths west and northwest into Michigan, causing a sequential loss of lines and power plants.

Key Events in This Phase

5A) 16:05:57 EDT: Sammis-Star 345-kV tripped by zone 3 relay.

5B) 16:08:59 EDT: Galion-Ohio Central-Muskingum 345-kV line tripped on zone 3 relay.

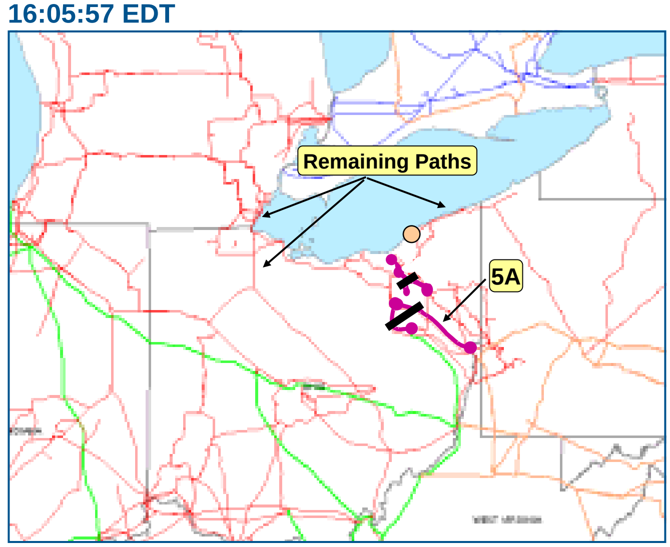
5C) 16:09:06 EDT: East Lima-Fostoria Central 345-kV line tripped on zone 3 relay, causing major power swings through New York and Ontario into Michigan.

5D) 16:09:08 EDT to 16:10:27 EDT: Several power plants lost, totaling 937 MW.

5A) Sammis-Star 345-kV Tripped: 16:05:57 EDT

Sammis-Star did not trip due to a short circuit to ground (as did the prior 345-kV lines that tripped). Sammis-Star tripped due to protective zone 3 relay action that measured low apparent impedance (depressed voltage divided by abnormally high line current) (Figure 6.4). There was no fault and no major power swing at the time of the trip—rather, high flows above the line's emergency rating together with depressed voltages caused the overload to appear to the protective relays as a remote fault on the system. In effect, the relay could no longer differentiate between a remote three-phase fault and an exceptionally high line-load condition. Moreover, the reactive flows (VAr) on the line were almost ten times higher than they had been earlier in the day because of the current overload. The relay operated as it was designed to do.

Figure 6.3. Sammis-Star 345-kV Line Trip, 16:05:57 EDT



The Sammis-Star 345-kV line trip completely severed the 345-kV path into northern Ohio from southeast Ohio, triggering a new, fast-paced sequence of 345-kV transmission line trips in which each line trip placed a greater flow burden on those lines remaining in service. These line outages left only three paths for power to flow into western Ohio: (1) from northwest Pennsylvania to northern Ohio around the south shore of Lake Erie, (2) from southwest Ohio toward northeast Ohio, and (3) from eastern Michigan and Ontario. The line interruptions substantially weakened northeast Ohio as a source of power to eastern Michigan, making the Detroit area more reliant on 345-kV lines west and northwest of Detroit, and from northwestern Ohio to eastern Michigan. The impact of this trip was felt across the grid—it caused a 100 MW increase in flow from PJM into New York and through to Ontario.[1] Frequency in the Eastern Interconnection increased momentarily by 0.02 Hz.

Soon after the Sammis-Star trip, four of the five 48 MW Handsome Lake combustion turbines in western Pennsylvania tripped off-line. These units are connected to the 345-kV system by the Homer City-Wayne 345-kV line, and were operating that day as synchronous condensers to participate in PJM's spinning reserve market (not to provide voltage support). When Sammis-Star tripped and increased loadings on the local transmission system, the Handsome Lake units were close enough electrically to sense the impact and tripped off-line at 16:07:00 EDT on under-voltage.

During the period between the Sammis-Star trip and the trip of East Lima-Fostoria at 16:09:06.3 EDT, the system was still in a steady-state condition. Although one line after another was overloading and tripping within Ohio, this was happening slowly enough under relatively stable conditions that the system could readjust—after each line loss, power flows would redistribute across the remaining lines. This is illustrated in Figure 6.5, which shows the MW flows on the Michigan Electrical Coordinated Systems (MECS) interfaces with AEP (Ohio), FirstEnergy (Ohio) and Ontario. The graph shows a shift from 150 MW imports to 200 MW exports from the MECS system into FirstEnergy at 16:05:57 EDT after the loss of Sammis-Star, after which this held steady until 16:08:59, when the loss of East Lima-Fostoria Central cut the main energy path from the south and west into Cleveland and Toledo. Loss of this path was significant, causing flow from MECS into FE to jump from 200 MW up to 2,300 MW, where it bounced somewhat before stabilizing, roughly, until the path across Michigan was cut at 16:10:38 EDT.

Transmission Lines into Northwestern Ohio Tripped, and Generation Tripped in South Central Michigan and Northern Ohio: 16:08:59 EDT to 16:10:27 EDT

5B) 16:08:59 EDT: Galion-Ohio Central-Muskingum 345-kV line tripped

5C) 16:09:06 EDT: East Lima-Fostoria Central 345-kV line tripped, causing a large power swing from Pennsylvania and New York through Ontario to Michigan

The tripping of the Galion-Ohio Central-Muskingum and East Lima-Fostoria Central

Figure 6.4. Sammis-Star 345-kV Line Trip

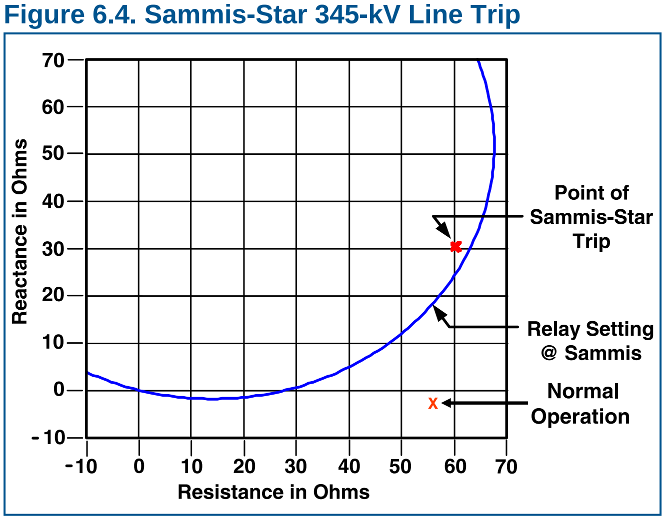
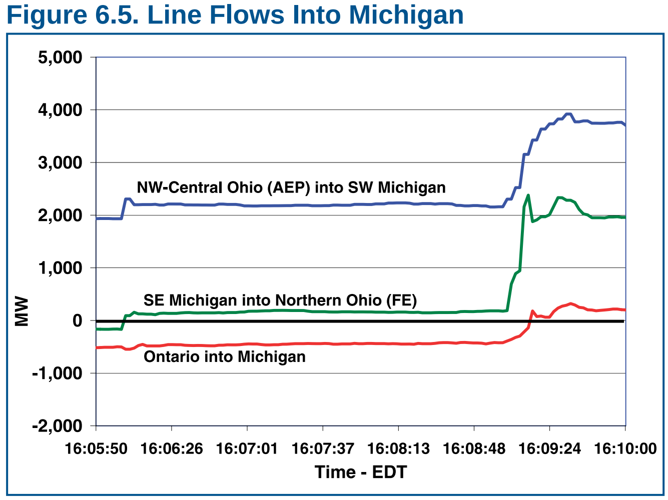


Figure 6.5. Line Flows Into Michigan



Note: These curves use data collected from the MECS Energy Management System, which records flow quantities every 2 seconds. As a result, the fast power swings that occurred between 16:10:36 to 16:13 were not captured by the recorders and are not reflected in these curves.

345-kV transmission lines removed the transmission paths from southern and western Ohio into northern Ohio and eastern Michigan. Northern Ohio was connected to eastern Michigan by only three 345-kV transmission lines near the southwestern bend of Lake Erie. Thus, the combined northern Ohio and eastern Michigan load centers were left connected to the rest of the grid only by: (1) transmission lines eastward from northeast Ohio to northwest Pennsylvania along the southern shore of Lake Erie, and (2) westward by lines west and northwest of Detroit, Michigan and from Michigan into Ontario (Figure 6.6).

The Galion-Ohio Central-Muskingum 345-kV line tripped first at Muskingum at 16:08:58.5 EDT on a phase-to-ground fault, reclosed and tripped again at 16:08:58.6 at Ohio Central, reclosed and tripped again at Muskingum on a Zone 3 relay, and finally tripped at Galion on a ground fault.

After the Galion-Ohio Central-Muskingum line outage and numerous 138-kV line trips in central Ohio, the East Lima-Fostoria Central 345-kV line tripped at 16:09:06 EDT on Zone 3 relay operation due to high current and extremely low voltage (80%). Investigation team modeling indicates that if automatic under-voltage load-shedding had been in place in northeast Ohio, it might have been triggered at or before this point, and dropped enough load to reduce or eliminate the subsequent line overloads that spread the cascade.

Recommendation s
8, page 147; 21, page 158

Figure 6.7, a high-speed recording of 345-kV flows past Niagara Falls from the Hydro One recorders, shows the impact of the East Lima-Fostoria Central and the New York to Ontario power swing, which continued to oscillate for over 10 seconds. Looking at the MW flow line, it is clear that when Sammis-Star tripped, the system experienced oscillations that quickly damped out and rebalanced. But East Lima-Fostoria triggered significantly greater oscillations that worsened in magnitude for several cycles, and returned to stability but continued to flutter until the Argenta-Battle Creek trip 90 seconds later. Voltages also began declining at this time.

After the East Lima-Fostoria Central trip, power flows increased dramatically and quickly on the lines into and across southern Michigan. Although power had initially been flowing northeast out of Michigan into Ontario, that flow suddenly reversed and approximately 500 to 700 MW of power (measured at the Michigan-Ontario border, and 437 MW at the Ontario-New York border at Niagara) flowed southwest out of Ontario through Michigan to serve the load of Cleveland and Toledo. This flow was fed by 700 MW pulled out of PJM through New York on its 345-kV network.[2] This was the first of several inter-area power and frequency events that occurred over the next two minutes. This was the system's response to the loss of the northwest Ohio transmission paths (above), and the stress that the still-high Cleveland, Toledo, and Detroit loads put onto the surviving lines and local generators.

Figure 6.7 also shows the magnitude of subsequent flows and voltages at the New York-Ontario Niagara border, triggered by the trips of the Argenta-Battle Creek, Argenta-Tompkins, Hampton-Pontiac and Thetford-Jewell 345-kV lines in Michigan, and the Erie West-Ashtabula-Perry

Figure 6.6. Ohio 345-kV Lines Trip, 16:08:59 to 16:09:07 EDT

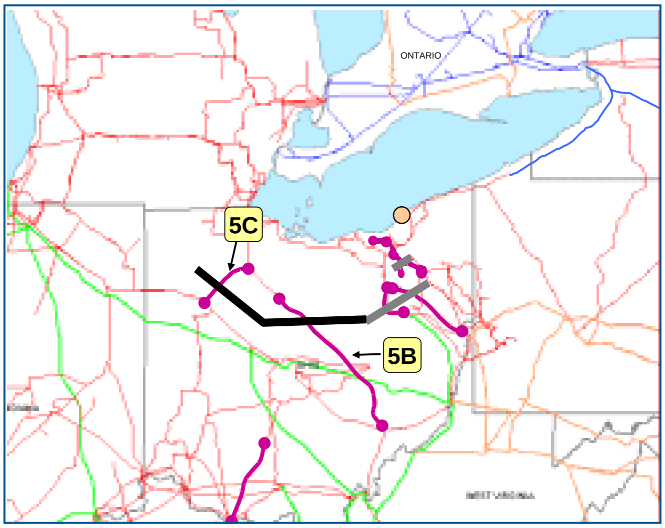
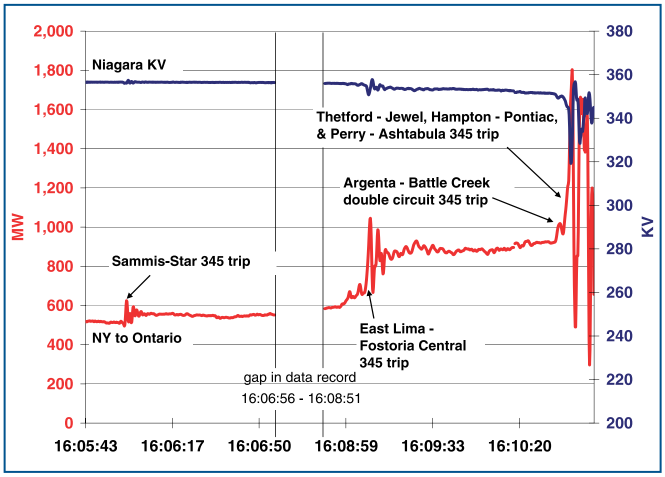


Figure 6.7. New York-Ontario Line Flows at Niagara



345-kV line linking the Cleveland area to Pennsylvania. Farther south, the very low voltages on the northern Ohio transmission system made it very difficult for the generation in the Cleveland and Lake Erie area to maintain synchronism with the Eastern Interconnection. Over the next two minutes, generators in this area shut down after reaching a point of no recovery as the stress level across the remaining ties became excessive.

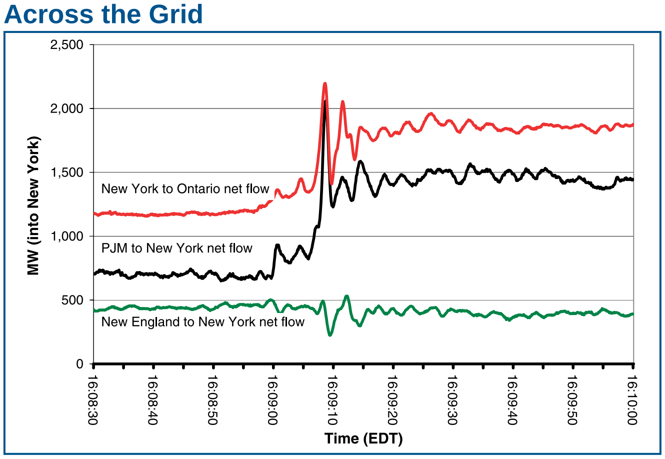
Figure 6.8, of metered power flows along the New York interfaces, documents how the flows heading north and west toward Detroit and Cleveland varied at different points on the grid. Beginning at 16:09:05 EDT, power flows jumped simultaneously across all three interfaces—but when the first power surge peaked at 16:09:09, the change in flow was highest on the PJM interface and lowest on the New England interface. Power flows increased significantly on the PJM-NY and NY-Ontario interfaces because of the redistribution of flow around Lake Erie. The New England and Maritime systems maintained the same generation to load balance and did not carry the redistributed flows because they were not in the direct path of the flows, so that interface with New York showed little response.

Before this first major power swing on the Michigan/Ontario interface, power flows in the NPCC Region (Québec, Ontario and the Maritimes, New England and New York) were typical for the summer period, and well within acceptable limits. Transmission and generation facilities were then in a secure state across the NPCC region.

Zone 3 Relays and the Start of the Cascade

Zone 3 relays are set to provide breaker failure and relay backup for remote distance faults on a transmission line. If it senses a fault past the immediate reach of the line and its zone 1 and zone 2 settings, a zone 3 relay waits through a 1 to 2 second time delay to allow the primary line protection to act first. A few lines have zone 3 settings designed with overload margins close to the long-term emergency limit of the line, because the length and configuration of the line dictate a higher apparent impedance setting. Thus it is possible for a zone 3 relay to operate on line load or overload in extreme contingency conditions even in the absence of a fault (which is why many regions in the United States and Canada have eliminated the use of zone 3 relays on 230-kV and greater lines). Some transmission operators set zone 2 relays to serve the same purpose as zone 3s—i.e., to reach well beyond the length of the line it is protecting and protect against a distant fault on the outer lines.

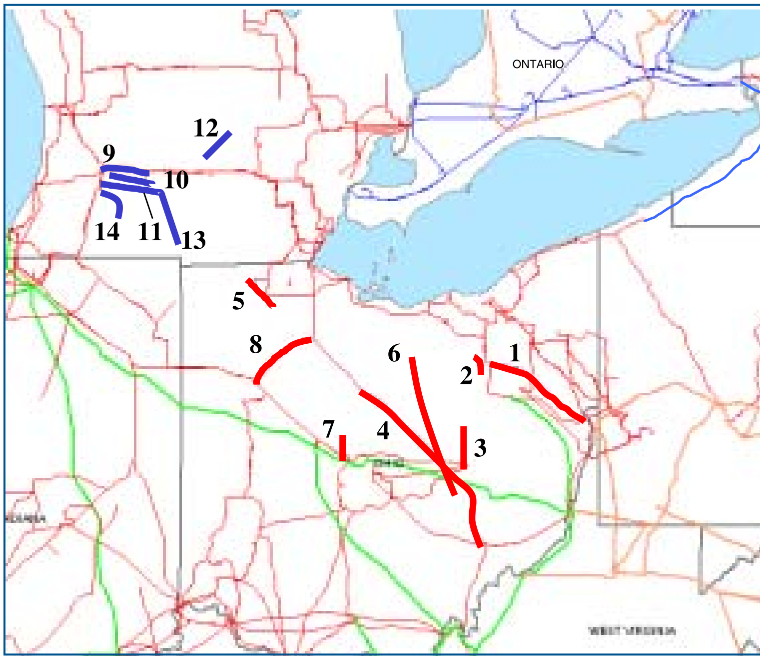
Figure 6.8. First Power Swing Has Varying Impacts Across the Grid



The Sammis-Star line tripped at 16:05:57 EDT on a zone 3 impedance relay although there were no faults occurring at the time, because increased real and reactive power flow caused the apparent impedance to be within the impedance circle (reach) of the relay. Between 16:06:01 and 16:10:38.6 EDT, thirteen more important 345 and 138-kV lines tripped on zone 3 operations that afternoon at the start of the cascade, including Galion-Ohio Central-Muskingum, East Lima-Fostoria Central, Argenta-Battle Creek, Argenta-Tompkins, Battle Creek-Oneida, and Perry-Ashtabula (Figure 6.9). These included several zone 2 relays in Michigan that had been set to operate like zone 3s, overreaching the line by more than 200% with no intentional time delay for remote breaker failure protection.[3] All of these relays operated according to their settings. However, the zone 3 relays (and zone 2 relays acting like zone 3s) acted so quickly that they impeded the natural ability of the electric system to hold together, and did not allow for any operator intervention to attempt to stop the spread of the cascade. The investigation team concluded that because these zone 2 and 3 relays tripped after each line overloaded, these relays were the common mode of failure that accelerated the geographic spread of the cascade. Given grid conditions and loads and the limited operator tools available, the speed of the zone 2 and 3 operations across Ohio and Michigan eliminated any possibility after 16:05:57 EDT that either operator action or automatic intervention could have limited or mitigated the growing cascade.

What might have happened on August 14 if these lines had not tripped on zone 2 and 3 relays? Each

Figure 6.9. Map of Zone 3 (and Zone 2s Operating Like Zone 3s) Relay Operations on August 14, 2003



	Zone 3 Tripped Lines	State	Trip Time (EDT)
1	Sammis - Star (345 kV)	Ohio	16:05:57.504
2	Star (138/69 kV) Transformer # 6 Star - Dale (69kV)	Ohio	16:06:01
3	Ohio CTL - Wooster (138 kV)	Ohio	16:08:58
4	Galion - Ohio CTL - Muskingum (345 kV) @ Muskingum	Ohio	16:08:59.158
5	Richland - Wauseon - Midway (138 kV)	Ohio	16:09:00
6	Academia - Howard (138 kV) Philo - Howard (138 kV)	Ohio	16:09:05
7	Tangy - Kirby (138 kV) Tangy - Crissinger (138 kV)	Ohio	16:09:06
8	E. Lima - Fostoria (345 kV)	Ohio	16:09:06.311
9	Argenta - Battle Ck (345 kV)	Michigan	16:10:36.230
10	Argenta - Tompkins (345 kV) Battle Ck - Oneida	Michigan	16:10:36.310
11	Argenta - Verona (138 kV)	Michigan	16:10:37.550
12	Delhi - Island Road (138 kV)	Michigan	16:10:37.870
13	Verona - Batavia (138 kV)	Michigan	16:10:37.900
14	Argenta - Morrow (138 kV)	Michigan	16:10:38.350

Voltage Collapse

Although the blackout of August 14 has been labeled by some as a voltage collapse, it was not a voltage collapse as that term has been traditionally used by power system engineers. Voltage collapse occurs when an increase in load or loss of generation or transmission facilities causes dropping voltage, which causes a further reduction in reactive power from capacitors and line charging, and still further voltage reductions. If the declines continue, these voltage reductions cause additional elements to trip, leading to further reduction in voltage and loss of load. The result is a progressive and uncontrollable decline in voltage, all because the power system is unable to provide the reactive power required to supply the reactive power demand. This did not occur on August 14. While the Cleveland-Akron area was short of reactive power reserves they were just sufficient to supply the reactive power demand in the area and maintain stable albeit depressed voltages for the outage conditions experienced.

But the lines in the Cleveland-Akron area tripped as a result of tree contacts well below the nominal rating of the lines and **not due to low voltages**, which is a precursor for voltage collapse. The initial trips within FirstEnergy began because of ground faults with untrimmed trees, not because of a shortage of reactive power and low voltages. Voltage levels were within workable bounds before individual transmission trips began, and those trips occurred within normal line ratings rather than in overloads. With fewer lines operational, current flowing over the remaining lines increased and voltage decreased (current increases in inverse proportion to the decrease in voltage for a given amount of power flow)—but it stabilized after each line trip until the next circuit trip. Soon northern Ohio lines began to trip out automatically on protection from overloads, not from insufficient reactive power. Once several lines tripped in the Cleveland-Akron area, the power flow was rerouted to other heavily loaded lines in northern Ohio, causing depressed voltages which led to automatic tripping on protection from overloads. Voltage collapse therefore was not a cause of the cascade.

As the cascade progressed beyond Ohio, it spread due not to insufficient reactive power and a voltage collapse, but because of dynamic power swings and the resulting system instability. Figure 6.7 shows voltage levels recorded at the Niagara area. It shows clearly that voltage levels remained stable until 16:10:30 EDT, despite significant power fluctuations. In the cascade that followed, the voltage instability was a companion to, not a driver of, the angle instability that tripped generators and lines.

was operating with high load, and loads on each line grew as each preceding line tripped out of service. But if these lines had not tripped quickly on zone 2s and 3s, each might have remained heavily loaded, with conductor temperatures increasing, for as long as 20 to 30 minutes before the line sagged into something and experienced a ground fault. For instance, the Dale-West Canton line took 20 minutes to trip under 160 to 180% of its normal rated load. Even with sophisticated modeling it is impossible to predict just how long this delay might have occurred (affected by wind speeds, line loadings, and line length, tension and ground clearance along every span), because the system did not become dynamically unstable until at least after the Thetford-Jewell trip at 16:10:38 EDT. During this period the system would likely have remained stable and been able to readjust after each line trip on ground fault. If this period of deterioration and overloading under stable conditions had lasted for as little as 15 minutes or as long as an hour, it is possible that the growing problems could have been recognized and action taken, such as automatic under-voltage load-shedding, manual load-shedding in Ohio or other measures. So although the operation of zone 2 and 3 relays in Ohio and Michigan did not cause the blackout, it is certain that they greatly expanded and accelerated the spread of the cascade.

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5D) Multiple Power Plants Tripped, Totaling 946 MW: 16:09:08 to 16:10:27 EDT

16:09:08 EDT: Michigan Cogeneration Venture plant reduction of 300 MW (from 1,263 MW to 963 MW)

16:09:17 EDT: Avon Lake 7 unit trips (82 MW)

16:09:17 EDT: Burger 3, 4, and 5 units trip (355 MW total)

16:09:30 EDT: Kinder Morgan units 3, 6 and 7 trip (209 MW total)

The Burger units tripped after the 138-kV lines into the Burger 138-kV substation (Ohio) tripped from the low voltages in the Cleveland area (Figure 6.10). The MCV plant is in central Michigan. Kinder Morgan is in south-central Michigan. The Kinder-Morgan units tripped due to a transformer fault and one due to over-excitation.

Power flows into Michigan from Indiana increased to serve loads in eastern Michigan and northern Ohio (still connected to the grid through northwest Ohio and Michigan) and voltages dropped from the imbalance between high loads and limited transmission and generation capability.

Phase 6: The Full Cascade

Between 16:10:36 EDT and 16:13 EDT, thousands of events occurred on the grid, driven by physics and automatic equipment operations. When it was over, much of the northeastern United States and the province of Ontario were in the dark.

Key Phase 6 Events

Transmission Lines Disconnected Across Michigan and Northern Ohio, Generation Shut Down in Central Michigan and Northern Ohio, and Northern Ohio Separated from Pennsylvania: 16:10:36 to 16:10:39 EDT

6A) Transmission and more generation tripped within Michigan: 16:10:36 to 16:10:37 EDT:

16:10:36.2 EDT: Argenta-Battle Creek 345-kV line tripped

16:10:36.3 EDT: Argenta-Tompkins 345-kV line tripped

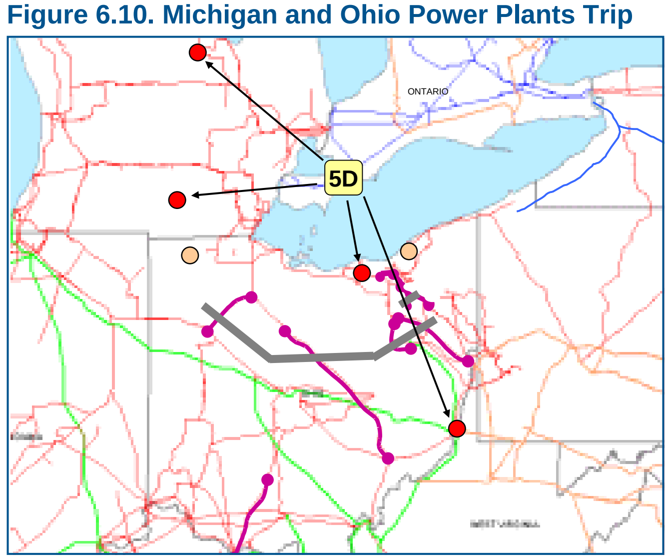
16:10:36.8 EDT: Battle Creek-Oneida 345-kV line tripped

16:10:37 EDT: Sumpter Units 1, 2, 3, and 4 units tripped on under-voltage (300 MW near Detroit)

16:10:37.5 EDT: MCV Plant output dropped from 963 MW to 109 MW on over-current protection.

Together, the above line outages interrupted the west-to-east transmission paths into the Detroit area from south-central Michigan. The Sumpter generation units tripped in response to

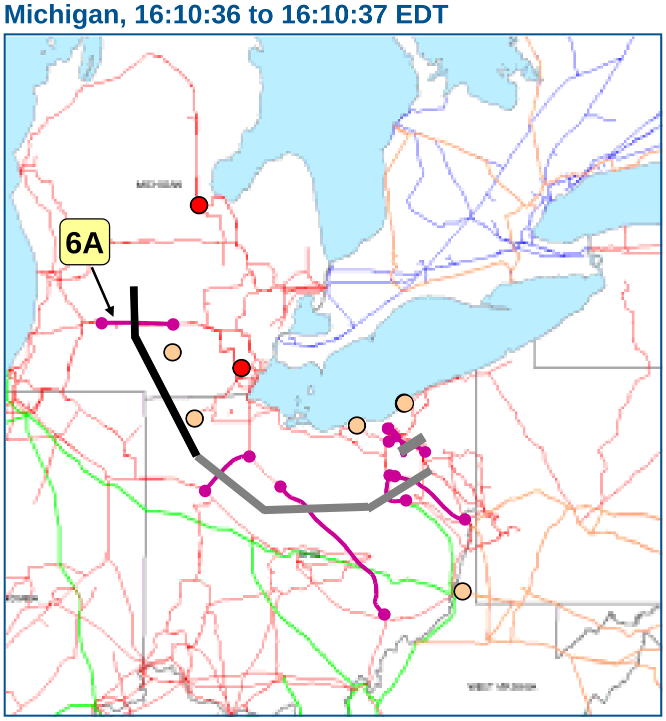
Figure 6.10. Michigan and Ohio Power Plants Trip



under-voltage on the system. Michigan lines west of Detroit then began to trip, as shown in Figure 6.11.

The Argenta-Battle Creek relay first opened the line at 16:10:36.230 EDT, reclosed it at 16:10:37, then tripped again. This line connects major generators—including the Cook and Palisades nuclear plants and the Campbell fossil plant—to the MECS system. This line is designed with auto-reclose breakers at each end of the line, which do an automatic high-speed reclose as soon as they open to restore the line to service with no interruptions. Since the majority of faults on the North American grid are temporary, automatic reclosing can enhance stability and system reliability. However, situations can occur when the power systems behind the two ends of the line could go out of phase during the high-speed reclose period (typically less than 30 cycles, or one half second, to allow the air to de-ionize after the trip to prevent arc re-ignition). To address this and protect generators from the harm that an out-of-synchronism reconnect could cause, it is worth studying whether a synchro-check relay is needed, to reclose the second breaker only when the two ends are within a certain voltage and phase angle tolerance. No such protection was installed at Argenta-Battle Creek; when the line reclosed, there was a 70º difference in phase across the circuit breaker reclosing the line. There is no evidence that the reclose caused harm to the local generators.

Figure 6.11. Transmission and Generation Trips in Michigan, 16:10:36 to 16:10:37 EDT



6B) Western and Eastern Michigan separation started: 16:10:37 EDT to 16:10:38 EDT

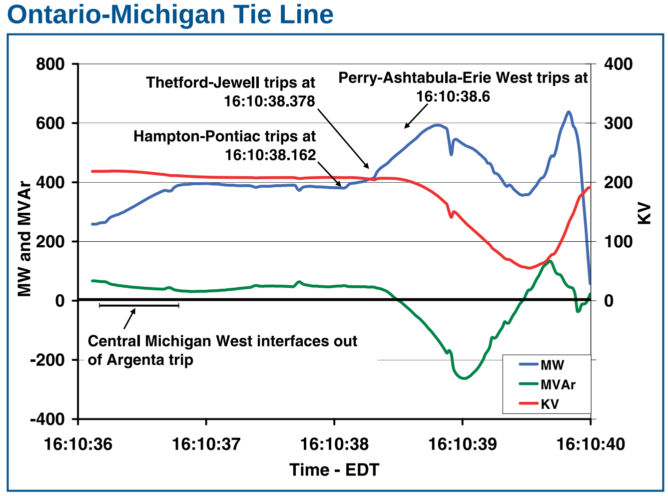
16:10:38.2 EDT: Hampton-Pontiac 345-kV line tripped

16:10:38.4 EDT: Thetford-Jewell 345-kV line tripped

After the Argenta lines tripped, the phase angle between eastern and western Michigan began to increase. The Hampton-Pontiac and Thetford-Jewell 345-kV lines were the only lines remaining connecting Detroit to power sources and the rest of the grid to the north and west. When these lines tripped out of service, it left the loads in Detroit, Toledo, Cleveland, and their surrounding areas served only by local generation and the lines north of Lake Erie connecting Detroit east to Ontario and the lines south of Lake Erie from Cleveland east to northwest Pennsylvania. These trips completed the extra-high voltage network separation between eastern and western Michigan.

The Power System Disturbance Recorders at Keith and Lambton, Ontario, captured these events in the flows across the Ontario-Michigan interface, as shown in Figure 6.12 and Figure 6.16. It shows clearly that the west to east Michigan separation (the Thetford-Jewell trip) was the start and Erie West-Ashtabula-Perry was the trigger for the 3,700 MW surge from Ontario into Michigan. When Thetford-Jewell tripped, power that had been flowing into Michigan and Ohio from western Michigan, western Ohio and Indiana was cut off. The nearby Ontario recorders saw a pronounced impact as flows into Detroit readjusted to draw power from the northeast instead. To the south,

Figure 6.12. Flows on Keith-Waterman 230-kV Ontario-Michigan Tie Line



Erie West-Ashtabula-Perry was the last 345-kV eastern link for northern Ohio loads. When that line severed, all the power that moments before had flowed across Michigan and Ohio paths was now diverted in a counter-clockwise direction around Lake Erie through the single path left in eastern Michigan, pulling power out of Ontario, New York and PJM.

Figures 6.13 and 6.14 show the results of investigation team modeling of the line loadings on the Ohio, Michigan, and other regional interfaces for the period between 16:05:57 until the Thetford-Jewell trip, to understand how power flows shifted during this period. The team simulated evolving system conditions on August 14, 2003, based on the 16:05:50 power flow case developed by the MAAC-ECAR-NPCC Operations Studies Working Group. Each horizontal line in the graph indicates a single or set of 345-kV lines and its loading as a function of normal ratings over time as first one, then another, set of circuits tripped out of service. In general, each subsequent line trip causes the remaining line loadings to rise; where a line drops (as Erie West-Ashtabula-Perry in Figure 6.13 after the Hanna-Juniper trip), that indicates that line loading lightened, most likely due to customers dropped from service. Note that Muskingum and East Lima-Fostoria Central were overloaded before they tripped, but the Michigan west and north interfaces were not overloaded before they tripped. Erie West-Ashtabula-Perry was loaded to 130% after the Hampton-Pontiac and Thetford-Jewell trips.

The Regional Interface Loadings graph (Figure 6.14) shows that loadings at the interfaces between PJM-NY, NY-Ontario and NY-New England were well within normal ratings before the east-west Michigan separation.

6C) Cleveland separated from Pennsylvania, flows reversed and a huge power surge flowed counter-clockwise around Lake Erie: 16:10:38.6 EDT

16:10:38.6 EDT: Erie West-Ashtabula-Perry 345-kV line tripped at Perry

16:10:38.6 EDT: Large power surge to serve loads in eastern Michigan and northern Ohio swept across Pennsylvania, New Jersey, and New York through Ontario into Michigan.

Perry-Ashtabula was the last 345-kV line connecting northern Ohio to the east south of Lake Erie. This line's trip at the Perry substation on a zone 3 relay operation separated the northern Ohio 345-kV transmission system from Pennsylvania and all eastern 345-kV connections. After this trip, the load centers in eastern Michigan and northern Ohio (Detroit, Cleveland, and Akron) remained connected to the rest of the Eastern Interconnection only to the north at the interface between the Michigan and Ontario systems (Figure 6.15). Eastern Michigan and northern Ohio now had little internal generation left and voltage was declining. The frequency in the Cleveland area dropped rapidly, and between 16:10:39 and 16:10:50 EDT under-frequency load shedding in the Cleveland area interrupted about 1,750 MW of load. However, the load shedding did not drop enough load relative to local generation to rebalance and arrest the frequency decline. Since the electrical system always seeks to balance load and generation, the high loads in Detroit and Cleveland drew power over the only major transmission path remaining—the lines from eastern Michigan into Ontario. Mismatches between generation and load are reflected in changes in frequency, so with more generation than load frequency rises and with less generation than load, frequency falls.

Figure 6.13. Simulated 345-kV Line Loadings from 16:05:57 through 16:10:38.4 EDT

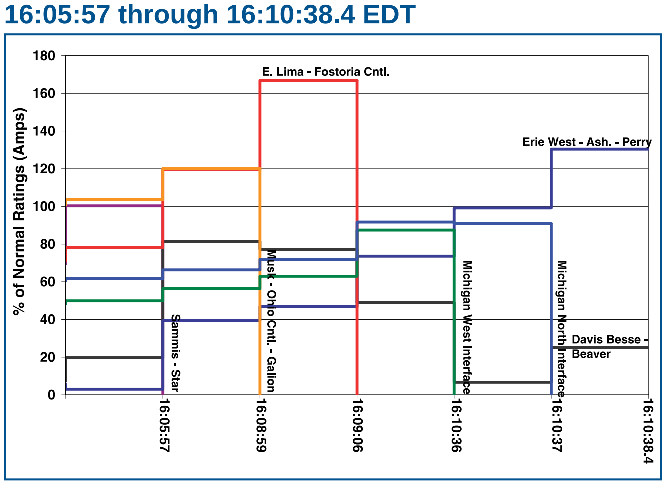
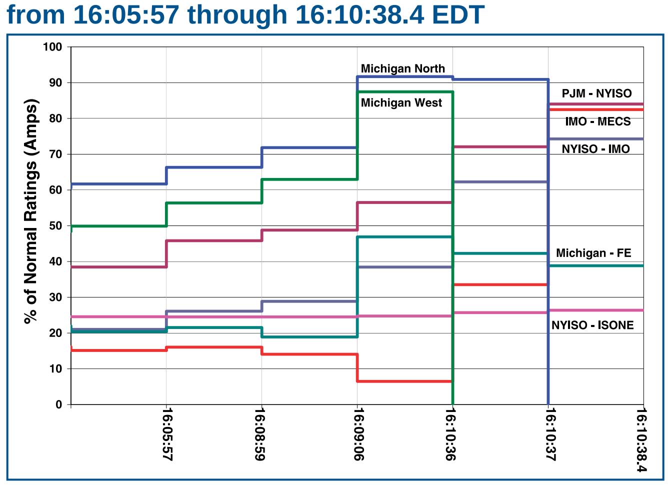


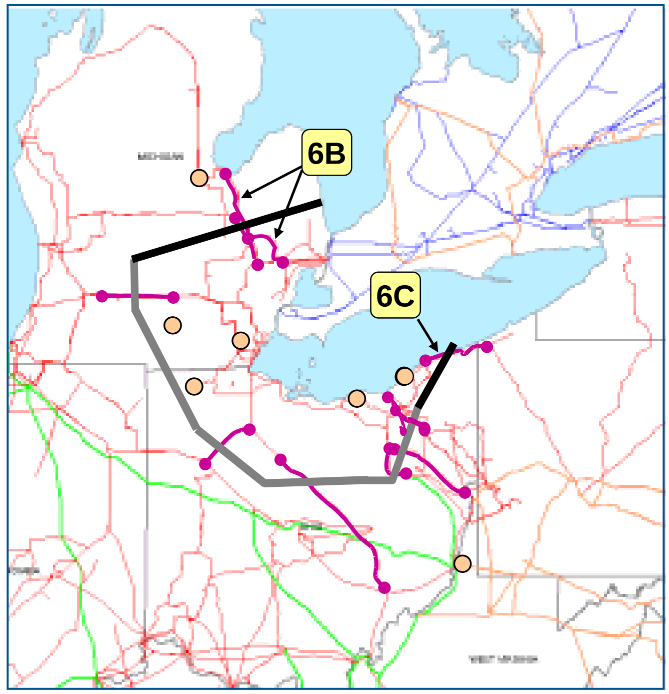
Figure 6.14. Simulated Regional Interface Loadings from 16:05:57 through 16:10:38.4 EDT



At 16:10:38.6 EDT, after the above transmission paths into Michigan and Ohio failed, the power that had been flowing at modest levels into Michigan from Ontario suddenly jumped in magnitude. While flows from Ontario into Michigan had been in the 250 to 350 MW range since 16:10:09.06 EDT, with this new surge they peaked at 3,700 MW at 16:10:39 EDT (Figure 6.16). Electricity moved along a giant loop through Pennsylvania and into New York and Ontario and then into Michigan via the remaining transmission path to serve the combined loads of Cleveland, Toledo, and Detroit. This sudden large change in power flows drastically lowered voltage and increased current levels on the transmission lines along the Pennsylvania-New York transmission interface.

This was a power surge of large magnitude, so frequency was not the same across the Eastern Interconnection. As Figure 6.16 shows, the power swing resulted in a rapid rate of voltage decay. Flows into Detroit exceeded 3,700 MW and 1,500 MVAr—the power surge was draining real power out of the northeast, causing voltages in Ontario and New York to drop. At the same time, local voltages in the Detroit area were plummeting because Detroit had already lost 500 MW of local generation. Detroit would soon lose synchronism and black out (as evidenced by the rapid power oscillations decaying after 16:10:43 EDT).

Figure 6.15. Michigan Lines Trip and Ohio Separates from Pennsylvania, 16:10:36 to 16:10:38.6 EDT



Modeling the Cascade

Computer modeling of the cascade built upon the modeling conducted of the pre-cascade system conditions described in Chapter 5. That earlier modeling developed steady-state load flow and voltage analyses for the entire Eastern Interconnection from 15:00 to 16:05:50 EDT. The dynamic modeling used the steady state load flow model for 16:05:50 as the starting point to simulate the cascade. Dynamic modeling conducts a series of load flow analyses, moving from one set of system conditions to another in steps one-quarter of a cycle long—in other words, to move one second from 16:10:00 to 16:10:01 requires simulation of 240 separate time slices.

The model used a set of equations that incorporate the physics of an electrical system. It contained detailed sub-models to reflect the characteristics of loads, under-frequency load-shedding, protective relay operations, generator operations (including excitation systems and governors), static VAr compensators and other FACTS devices, and transformer tap changers.

The modelers compared model results at each moment to actual system data for that moment to verify a close correspondence for line flows and voltages. If there was too much of a gap between modeled and actual results, they looked at the timing of key events to see whether actual data might have been mis-recorded, or whether the modeled variance for an event not previously recognized as significant might influence the outcome. Through 16:10:40 EDT, the team achieved very close benchmarking of the model against actual results.

The modeling team consisted of industry members from across the Midwest, Mid-Atlantic and NPCC areas. All have extensive electrical engineering and/or mathematical training and experience as system planners for short- or long-term operations.

This modeling allows the team to verify its hypotheses as to why particular events occurred and the relationships between different events over time. It allows testing of many "what if" scenarios and alternatives, to determine whether a change in system conditions might have produced a different outcome.

Just before the Argenta-Battle Creek trip, when Michigan separated west to east at 16:10:37 EDT, almost all of the generators in the eastern interconnection were moving in synchronism with the overall grid frequency of 60 Hertz (shown at the bottom of Figure 6.17), but when the swing started, those machines absorbed some of its energy as they attempted to adjust and resynchronize with the rapidly changing frequency. In many cases, this adjustment was unsuccessful and the generators tripped out from milliseconds to several seconds thereafter.

The Perry-Ashtabula-Erie West 345-kV line trip at 16:10:38.6 EDT was the point when the Northeast entered a period of transient instability and a loss of generator synchronism. Between 16:10:38 and 16:10:41 EDT, the power swings caused a sudden extraordinary increase in system frequency, hitting 60.7 Hz at Lambton and 60.4 Hz at Niagara.

Because the demand for power in Michigan, Ohio, and Ontario was drawing on lines through New York and Pennsylvania, heavy power flows were moving northward from New Jersey over the New York tie lines to meet those power demands, exacerbating the power swing. Figure 6.17 shows actual net line flows summed across the interfaces between the main regions affected by these swings—Ontario into Michigan, New York into Ontario, New York into New England, and PJM into New York. This shows clearly that the power swings did not move in unison across every interface at every moment, but varied in magnitude and direction. This occurred for two reasons. First, the availability of lines to complete the path across

Figure 6.16. Active and Reactive Power and Voltage from Ontario into Detroit

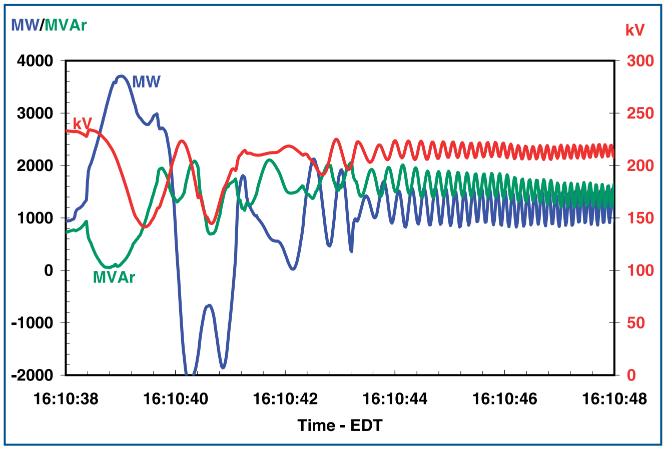
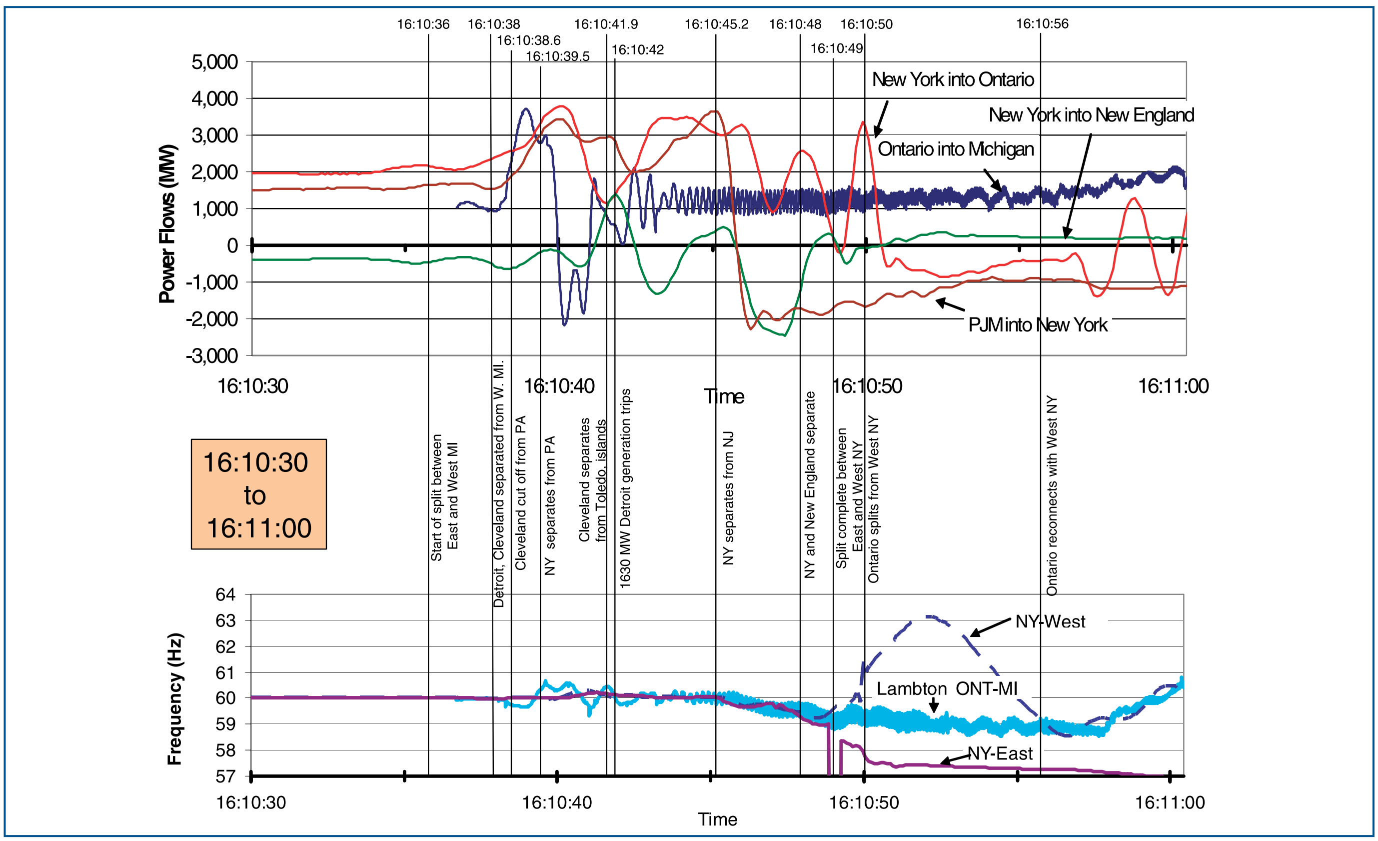


Figure 6.17. Measured Power Flows and Frequency Across Regional Interfaces, 16:10:30 to 16:11:00 EDT, with Key Events in the Cascade



each interface varied over time, as did the amount of load that drew upon each interface, so net flows across each interface were not facing consistent demand with consistent capability as the cascade progressed. Second, the speed and magnitude of the swing was moderated by the inertia, reactive power capabilities, loading conditions and locations of the generators across the entire region.

After Cleveland was cut off from Pennsylvania and eastern power sources, Figure 6.17 shows the start of the dynamic power swing at 16:10:38.6. Because the loads of Cleveland, Toledo and Detroit (less the load already blacked out) were now hanging off Michigan and Ontario, this forced a gigantic shift in power flows to meet that demand. As noted above, flows from Ontario into Michigan increased from 1,000 MW to 3,700 MW shortly after the start of the swing, while flows from PJM into New York were close behind. But within two seconds from the start of the swing, at 16:10:40 EDT flows reversed and coursed back from Michigan into Ontario at the same time that frequency at the interface dropped, indicating that significant generation had been lost. Flows that had been westbound across the Ontario-Michigan interface by over 3,700 MW at 16:10:38.8 dropped down to 2,100 MW eastbound by 16:10:40, and then returned westbound starting at 16:10:40.5.

A series of circuits tripped along the border between PJM and the NYISO due to zone 1 impedance relay operations on overload and depressed voltage. The surge also moved into New England and the Maritimes region of Canada. The combination of the power surge and frequency rise caused 380 MW of pre-selected Maritimes generation to drop off-line due to the operation of the New Brunswick Power "Loss of Line 3001" Special Protection System. Although this system was designed to respond to failure of the 345-kV link between the Maritimes and New England, it operated in response to the effects of the power surge. The link remained intact during the event.

6D) Conditions in Northern Ohio and Eastern Michigan Degraded Further, With More Transmission Lines and Power Plants Failing: 16:10:39 to 16:10:46 EDT

Line trips in Ohio and eastern Michigan:

- 16:10:39.5 EDT: Bay Shore-Monroe 345-kV line
- 16:10:39.6 EDT: Allen Junction-Majestic-Monroe 345-kV line
- 16:10:40.0 EDT: Majestic-Lemoyne 345-kV line
- Majestic 345-kV Substation: one terminal opened sequentially on all 345-kV lines
- 16:10:41.8 EDT: Fostoria Central-Galion 345-kV line
- 16:10:41.911 EDT: Beaver-Davis Besse 345-kV line

Under-frequency load-shedding in Ohio:

- FirstEnergy shed 1,754 MVA load
- AEP shed 133 MVA load

Seven power plants, for a total of 3,294 MW of generation, tripped off-line in Ohio:

- 16:10:42 EDT: Bay Shore Units 1-4 (551 MW near Toledo) tripped on over-excitation
- 16:10:40 EDT: Lakeshore unit 18 (156 MW, near Cleveland) tripped on under-frequency
- 16:10:41.7 EDT: Eastlake 1, 2, and 3 units (304 MW total, near Cleveland) tripped on under-frequency
- 16:10:41.7 EDT: Avon Lake unit 9 (580 MW, near Cleveland) tripped on under-frequency
- 16:10:41.7 EDT: Perry 1 nuclear unit (1,223 MW, near Cleveland) tripped on under-frequency
- 16:10:42 EDT: Ashtabula unit 5 (184 MW, near Cleveland) tripped on under-frequency
- 16:10:43 EDT: West Lorain units (296 MW) tripped on under-voltage

Four power plants producing 1,759 MW tripped off-line near Detroit:

- 16:10:42 EDT: Greenwood unit 1 tripped (253 MW) on low voltage, high current
- 16:10:41 EDT: Belle River unit 1 tripped (637 MW) on out-of-step
- 16:10:41 EDT: St. Clair unit 7 tripped (221 MW, DTE unit) on high voltage
- 16:10:42 EDT: Trenton Channel units 7A, 8 and 9 tripped (648 MW)

Back in northern Ohio, the trips of the Bay Shore-Monroe, Majestic-Lemoyne, Allen Junction-Majestic-Monroe 345-kV lines, and the Ashtabula 345/138-kV transformer cut off Toledo and Cleveland from the north, turning that area into an electrical island (Figure 6.18). Frequency in this large island began to fall rapidly. This caused a series of power plants in the area to trip off-line due to the operation of under-frequency relays, including the Bay Shore units. When the Beaver-Davis Besse 345-kV line between Cleveland and Toledo tripped, it left the Cleveland area completely isolated and area frequency rapidly declined. Cleveland area load was disconnected by automatic under-frequency load-shedding (approximately 1,300 MW), and another 434 MW of load was interrupted after the generation remaining within this transmission "island" was tripped by under-frequency relays. This sudden load drop would contribute to the reverse power swing. In its own island, portions of Toledo blacked out from automatic under-frequency load-shedding but most of the Toledo load was restored by automatic reclosing of lines such as the East Lima-Fostoria Central 345-kV line and several lines at the Majestic 345-kV substation.

The Perry nuclear plant is in Ohio on Lake Erie, not far from the Pennsylvania border. The Perry plant was inside a decaying electrical island, and the plant tripped on under-frequency, as designed. A number of other units near Cleveland tripped off-line by under-frequency protection.

The tremendous power flow into Michigan, beginning at 16:10:38, occurred when Toledo and Cleveland were still connected to the grid only through Detroit. After the Bay Shore-Monroe line tripped at 16:10:39, Toledo-Cleveland were separated into their own island, dropping a large amount of load off the Detroit system. This left Detroit suddenly with excess generation, much of which was greatly accelerated in angle as the depressed voltage in Detroit (caused by the high demand in Cleveland) caused the Detroit units to pull nearly out of step. With the Detroit generators running at maximum mechanical output, they began to pull out of synchronous operation with the rest of the grid. When voltage in Detroit returned to near-normal, the generators could not fully pull back its rate of revolutions, and ended up producing excessive temporary output levels, still out of step with the system. This is evident in Figure 6.19, which shows at least two sets of generator "pole slips" by plants in the Detroit area between 16:10:40 EDT and 16:10:42 EDT. Several large units around Detroit—Belle River, St. Clair, Greenwood, Monroe, and Fermi—all tripped in response. After formation of the Cleveland-Toledo island at 16:10:40 EDT, Detroit frequency spiked to almost 61.7 Hz before dropping, momentarily equalized between the Detroit and Ontario systems, but Detroit frequency began to decay at 2 Hz/sec and the generators then experienced under-speed conditions.

Re-examination of Figure 6.17 shows the power swing from the northeast through Ontario into Michigan and northern Ohio that began at 16:10:37, and how it reverses and swings back around Lake Erie at 16:10:39 EDT. That return was caused by the combination of natural oscillations, accelerated by major load losses, as the northern Ohio system disconnected from Michigan. It caused a power flow change of 5,800 MW, from 3,700 MW westbound to 2,100 eastbound across the Ontario to Michigan border between 16:10:39.5 and 16:10:40 EDT. Since the system was now fully dynamic, this large oscillation eastbound would lead naturally to a rebound, which began at 16:10:40 EDT with an inflection point reflecting generation shifts between Michigan and Ontario and additional line losses in Ohio.

Figure 6.18. Cleveland and Toledo Islanded, 16:10:39 to 16:10:46 EDT

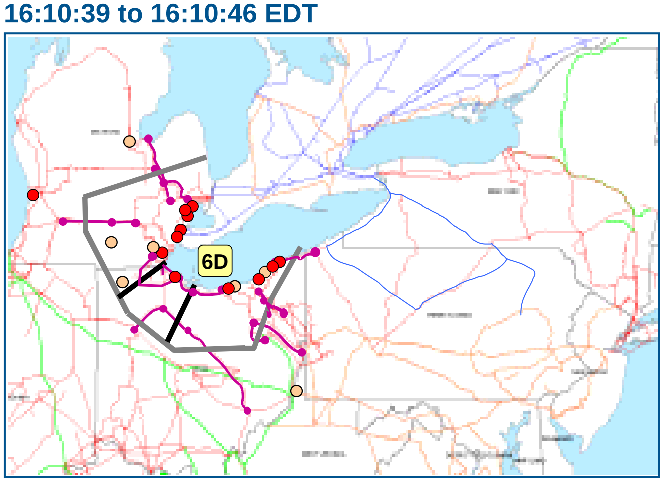
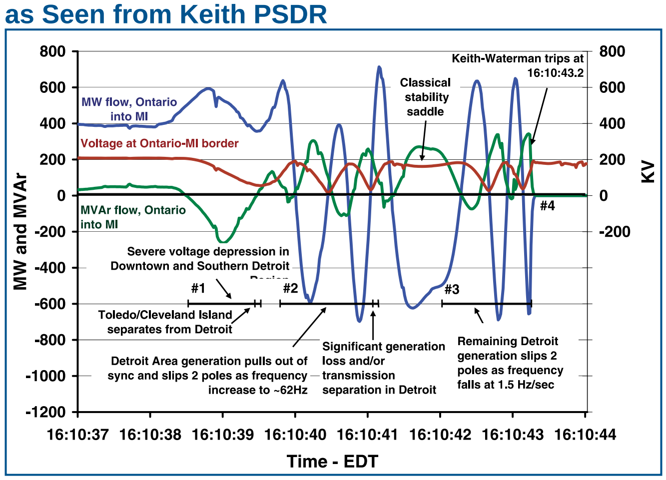


Figure 6.19. Generators Under Stress in Detroit, as Seen from Keith PSDR



Western Pennsylvania Separated from New York: 16:10:39 EDT to 16:10:44 EDT

6E) 16:10:39 EDT, Homer City-Watercure Road 345 kV

16:10:39 EDT: Homer City-Stolle Road 345 kV

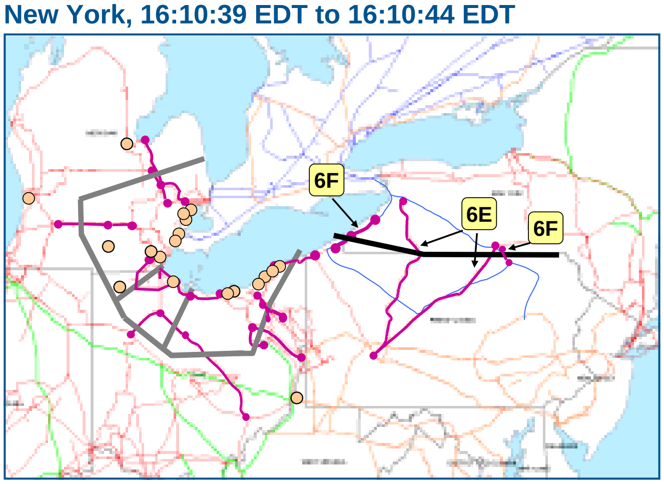
6F) 16:10:44 EDT: South Ripley-Erie East 230 kV, and South Ripley-Dunkirk 230 kV

16:10:44 EDT: East Towanda-Hillside 230 kV

Responding to the swing of power out of Michigan toward Ontario and into New York and PJM, zone 1 relays on the 345-kV lines separated Pennsylvania from New York (Figure 6.20). Homer City-Watercure (177 miles or 285 km) and Homer City-Stolle Road (207 miles or 333 km) are very long lines and so have high impedance. Zone 1 relays do not have timers, and operate instantly when a power swing enters the relay target circle. For normal length lines, zone 1 relays have small target circles because the relay is measuring a less than the full length of the line—but for a long line the large line impedance enlarges the relay's target circle and makes it more likely to be hit by the power swing. The Homer City-Watercure and Homer City-Stolle Road lines do not have zone 3 relays.

Given the length and impedance of these lines, it was highly likely that they would trip and separate early in the face of such large power swings. Most of the other interfaces between regions are on short ties—for instance, the ties between New York and Ontario and Ontario to Michigan are only about 2 miles (3.2 km) long, so they are electrically very short and thus have much lower impedance and trip less easily than these long lines. A zone 1 relay target for a short line covers a small area so a power swing is less likely to enter the relay target circle at all, averting a zone 1 trip.

Figure 6.20. Western Pennsylvania Separates from New York, 16:10:39 EDT to 16:10:44 EDT



At 16:10:44 EDT, the northern part of the Eastern Interconnection (including eastern Michigan) was connected to the rest of the Interconnection at only two locations: (1) in the east through the 500-kV and 230-kV ties between New York and northeast New Jersey, and (2) in the west through the long and electrically fragile 230-kV transmission path connecting Ontario to Manitoba and Minnesota. The separation of New York from Pennsylvania (leaving only the lines from New Jersey into New York connecting PJM to the northeast) buffered PJM in part from these swings. Frequency was high in Ontario at that point, indicating that there was more generation than load, so much of this flow reversal never got past Ontario into New York.

6G) Transmission paths disconnected in New Jersey and northern Ontario, isolating the northeast portion of the Eastern Interconnection: 16:10:43 to 16:10:45 EDT

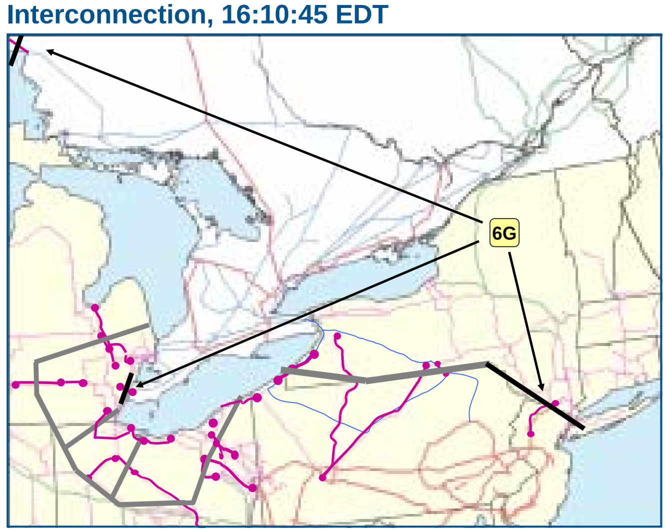
16:10:43 EDT: Keith-Waterman 230-kV line tripped

16:10:45 EDT: Wawa-Marathon 230-kV lines tripped

16:10:45 EDT: Branchburg-Ramapo 500-kV line tripped

At 16:10:43 EDT, eastern Michigan was still connected to Ontario, but the Keith-Waterman 230-kV line that forms part of that interface disconnected due to apparent impedance (Figure 6.21). This put more power onto the remaining interface between Ontario and Michigan, but

Figure 6.21. Northeast Separates from Eastern Interconnection, 16:10:45 EDT



triggered sustained oscillations in both power flow and frequency along the remaining 230-kV line.

At 16:10:45 EDT, northwest Ontario separated from the rest of Ontario when the Wawa-Marathon 230-kV lines (104 miles or 168 km long) disconnected along the northern shore of Lake Superior, tripped by zone 1 distance relays at both ends. This separation left the loads in the far northwest portion of Ontario connected to the Manitoba and Minnesota systems, and protected them from the blackout.

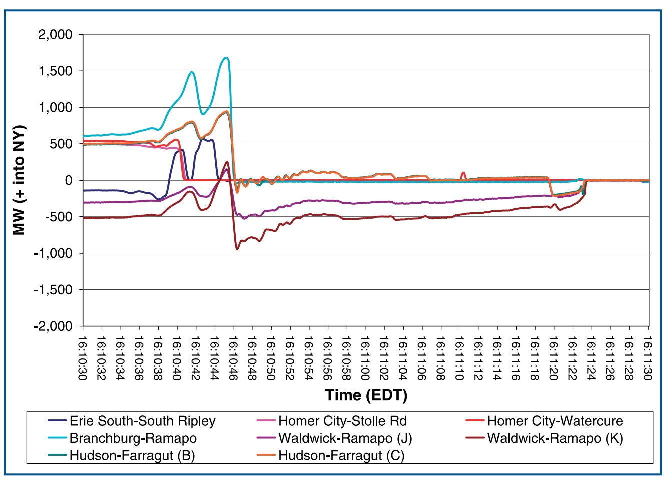
The 69-mile (111 km) long Branchburg-Ramapo 500-kV line and Ramapo transformer between New Jersey and New York was the last major transmission path remaining between the Eastern Interconnection and the area ultimately affected by the blackout. Figure 6.22 shows how that line disconnected at 16:10:45 EDT, along with other underlying 230 and 138-kV lines in northeast New Jersey. Branchburg–Ramapo was carrying over 3,000 MVA and 4,500 amps with voltage at 79% before it tripped, either on a high-speed swing into zone 1 or on a direct transfer trip. The investigation team is still examining why the higher impedance 230-kV overhead lines tripped while the underground Hudson-Farragut 230-kV cables did not; the available data suggest that the notably lower impedance of underground cables made these less vulnerable to the electrical strain placed on the system.

This left the northeast portion of New Jersey connected to New York, while Pennsylvania and the rest of New Jersey remained connected to the rest of the Eastern Interconnection. Within northeast New Jersey, the separation occurred along the 230-kV corridors which are the main supply feeds into the northern New Jersey area (the two Roseland-Athenia circuits and the Linden-Bayway circuit). These circuits supply the large customer load in northern New Jersey and are a primary route for power transfers into New York City, so they are usually more highly loaded than other interfaces. These lines tripped west and south of the large customer loads in northeast New Jersey.

The separation of New York, Ontario, and New England from the rest of the Eastern Interconnection occurred due to natural breaks in the system and automatic relay operations, which performed exactly as they were designed to. No human intervention occurred by operators at PJM headquarters or elsewhere to effect this split. At this point, the Eastern Interconnection was divided into two major sections. To the north and east of the separation point lay New York City, northern New Jersey, New York state, New England, the Canadian Maritime Provinces, eastern Michigan, the majority of Ontario, and the Québec system.

The rest of the Eastern Interconnection, to the south and west of the separation boundary, was not seriously affected by the blackout. Frequency in the Eastern Interconnection was 60.3 Hz at the time of separation; this means that approximately 3,700 MW of excess generation that was on-line to export into the northeast was now in the main Eastern Island, separated from the load it had been serving. This left the northeast island with even less in-island generation on-line as it attempted to rebalance in the next phase of the cascade.

Figure 6.22. PJM to New York Interties Disconnect



Note: The data in this figure come from the NYISO Energy Management System SDAC high speed analog system, which records 10 samples per second.

Phase 7: Several Electrical Islands Formed in Northeast U.S. and Canada: 16:10:46 EDT to 16:12 EDT

Overview of This Phase

During the next 3 seconds, the islanded northern section of the Eastern Interconnection broke apart internally. Figure 6.23 illustrates the events of this phase.

7A) New York-New England upstate transmission lines disconnected: 16:10:46 to 16:10:47 EDT

7B) New York transmission system split along Total East interface: 16:10:49 EDT

7C) The Ontario system just west of Niagara Falls and west of St. Lawrence separated from the western New York island: 16:10:50 EDT

7D) Southwest Connecticut separated from New York City: 16:11:22 EDT

7E) Remaining transmission lines between Ontario and eastern Michigan separated: 16:11:57 EDT

By this point most portions of the affected area were blacked out.

If the 6th phase of the cascade was about dynamic system oscillations, the last phase is a story of the search for balance between loads and generation. Here it is necessary to understand three matters related to system protection—why the blackout stopped where it did, how and why under-voltage and under-frequency load-shedding work, and what happened to the generators on August 14 and why. These matter because loads and generation must ultimately balance in real-time to remain stable. When the grid is breaking apart into islands, if generators stay on-line longer, then the better the chances to keep the lights on within each island and restore service following a blackout; so automatic load-shedding, transmission relay protections and generator protections must avoid premature tripping. They must all be coordinated to reduce the likelihood of system break-up, and once break-up occurs, to maximize an island's chances for electrical survival.

Why the Blackout Stopped Where It Did

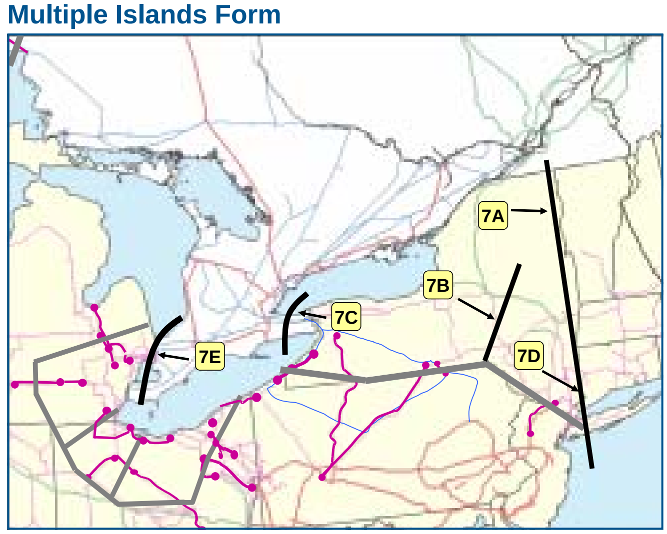
Extreme system conditions can damage equipment in several ways, from melting aluminum conductors (excessive currents) to breaking turbine blades on a generator (frequency excursions). The power system is designed to ensure that if conditions on the grid (excessive or inadequate voltage, apparent impedance or frequency) threaten the safe operation of the transmission lines, transformers, or power plants, the threatened equipment automatically separates from the network to protect itself from physical damage. Relays are the devices that effect this protection.

Generators are usually the most expensive units on an electrical system, so system protection schemes are designed to drop a power plant off the system as a self-protective measure if grid conditions become unacceptable. This protective measure leaves the generator in good condition to help rebuild the system once a blackout is over and restoration begins. When unstable power swings develop between a group of generators that are losing synchronization (unable to match frequency) with the rest of the system, one effective way to stop the oscillations is to stop the flows entirely by disconnecting the unstable generators from the remainder of the system. The most common way to protect generators from power oscillations is for the transmission system to detect the power swings and trip at the locations detecting the swings—ideally before the swing reaches critical levels and harms the generator or the system.

On August 14, the cascade became a race between the power surges and the relays. The lines that tripped first were generally the longer lines with relay settings using longer apparent impedance tripping zones and normal time settings. On August 14, relays on long lines such as the Homer City-Watercure and the Homer City-Stolle Road 345-kV lines in Pennsylvania, that are not highly integrated into the electrical network, tripped quickly and split the grid between the sections that blacked out and those that recovered without further propagating the cascade. This same phenomenon was seen in the Pacific Northwest blackouts of 1996, when long lines tripped before more networked, electrically supported lines.

Transmission line voltage divided by its current flow is called "apparent impedance." Standard transmission line protective relays continuously measure apparent impedance. When apparent impedance drops within the line's protective relay set-points for a given period of time, the relays trip

Figure 6.23. New York and New England Separate, Multiple Islands Form



the line. The vast majority of trip operations on lines along the blackout boundaries between PJM and New York (for instance) show high-speed relay targets which indicate that a massive power surge caused each line to trip. To the relays, this power surge altered the voltages and currents enough that they appeared to be faults. The power surge was caused by power flowing to those areas that were generation-deficient (Cleveland, Toledo and Detroit) or rebounding back. These flows occurred purely because of the physics of power flows, with no regard to whether the power flow had been scheduled, because power flows from areas with excess generation into areas that were generation-deficient.

Protective relay settings on transmission lines operated as they were designed and set to behave on August 14. In some cases line relays did not trip in the path of a power surge because the apparent impedance on the line was not low enough—not because of the magnitude of the current, but rather because voltage on that line was high enough that the resulting impedance was adequate to avoid entering the relay's target zone. Thus relative voltage levels across the northeast also affected which areas blacked out and which areas stayed on-line.

In the U.S. Midwest, as voltage levels declined many generators in the affected area were operating at maximum reactive power output before the blackout. This left the system little slack to deal with the low voltage conditions by ramping up more generators to higher reactive power output levels, so there was little room to absorb any system "bumps" in voltage or frequency. In contrast, in the northeast—particularly PJM, New York, and ISO-New England—operators were anticipating high power demands on the afternoon of August 14, and had already set up the system to maintain higher voltage levels and therefore had more reactive reserves on-line in anticipation of later afternoon needs. Thus, when the voltage and frequency swings began, these systems had reactive power readily available to help buffer their areas against potential voltage collapse without widespread generation trips.

The investigation team has used simulation to examine whether special protection schemes, designed to detect an impending cascade and separate the grid at specific interfaces, could have been or should be set up to stop a power surge and prevent it from sweeping through an interconnection and causing the breadth of line and generator trips and islanding that occurred that day. The team has concluded that such schemes would have been ineffective on August 14.

Under-Frequency and Under-Voltage Load-Shedding

Automatic load-shedding measures are designed into the electrical system to operate as a last resort, under the theory that it is wise to shed some load in a controlled fashion if it can forestall the loss of a great deal of load to an uncontrollable cause. Thus there are two kinds of automatic load-shedding installed in North America—under-voltage load-shedding, which sheds load to prevent local area voltage collapse, and under-frequency load-shedding, which is designed to rebalance load and generation within an electrical island once it has been created by a system disturbance.

Automatic under-voltage load-shedding (UVLS) responds directly to voltage conditions in a local area. UVLS drops several hundred MW of load in pre-selected blocks within urban load centers, triggered in stages when local voltage drops to a designated level—likely 89 to 92% or even higher—with a several second delay. The goal of a UVLS scheme is to eliminate load in order to restore reactive power relative to demand, to prevent voltage collapse and contain a voltage problem within a local area rather than allowing it to spread in geography and magnitude. If the first load-shed step does not allow the system to rebalance, and voltage continues to deteriorate, then the next block of UVLS is dropped. Use of UVLS is not mandatory, but is done at the option of the control area and/or reliability council. UVLS schemes and trigger points should be designed to respect the local area's system vulnerabilities, based on voltage collapse studies. As noted in Chapter 4, there is no UVLS system in place within Cleveland and Akron; had such a scheme been implemented before August, 2003, shedding 1,500 MW of load in that area before the loss of the Sammis-Star line might have prevented the cascade and blackout.

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In contrast to UVLS, automatic under-frequency load-shedding (UFLS) is designed for use in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow frequency to stabilize within the island. All synchronous generators in North America are designed to operate at 60 cycles per second

(Hertz) and frequency reflects how well load and generation are balanced—if there is more load than generation at any moment, frequency drops below 60 Hz, and it rises above that level if there is more generation than load. By dropping load to match available generation within the island, UFLS is a safety net that helps to prevent the complete blackout of the island, which allows faster system restoration afterward. UFLS is not effective if there is electrical instability or voltage collapse within the island.

Today, UFLS installation is a NERC requirement, designed to shed at least 25-30% of the load in steps within each reliability coordinator region. These systems are designed to drop pre-designated customer load automatically if frequency gets too low (since low frequency indicates too little generation relative to load), starting generally when frequency reaches 59.3 Hz. Progressively more load is set to drop as frequency levels fall farther. The last step of customer load shedding is set at the frequency level just above the set point for generation under-frequency protection relays (57.5 Hz), to prevent frequency from falling so low that generators could be damaged (see Figure 2.4).

In NPCC, following the Northeast blackout of 1965, the region adopted automatic under-frequency load-shedding criteria and manual load-shedding within ten minutes to prevent a recurrence of the cascade and better protect system equipment from damage due to a high-speed system collapse. Under-frequency load-shedding triggers vary by regional reliability council—New York and all of the Northeast Power Coordinating Council, plus the Mid-Atlantic Area Council use 59.3 Hz as the first step for UFLS, while ECAR uses 59.5 Hz as their first step for UFLS.

The following automatic UFLS operated on the afternoon of August 14:

- Ohio shed over 1,883 MVA beginning at 16:10:39 EDT
- Michigan shed a total of 2,835 MW
- New York shed a total of 10,648 MW in numerous steps, beginning at 16:10:48
- PJM shed a total of 1,324 MVA in 3 steps in northern New Jersey beginning at 16:10:48 EDT
- Ontario shed a total of 7,800 MW in 2 steps, beginning at 16:10:4
- New England shed a total of 1,098 MW.

It must be emphasized that the entire northeast system was experiencing large scale, dynamic oscillations in this period. Even if the UFLS and generation had been perfectly balanced at any moment in time, these oscillations would have made stabilization difficult and unlikely.

Why the Generators Tripped Off

At least 265 power plants with more than 508 individual generating units shut down in the August 14 blackout. These U.S. and Canadian plants can be categorized as follows:

By reliability coordination area:

- Hydro Québec, 5 plants (all isolated onto the Ontario system)[4]
- Ontario, 92 plants
- ISO-New England, 31 plants
- MISO, 32 plants
- New York ISO, 70 plants
- PJM, 35 plants

By type:

- Conventional steam units, 66 plants (37 coal)
- Combustion turbines, 70 plants (37 combined cycle)
- Nuclear, 10 plants—7 U.S. and 3 Canadian, totaling 19 units (the nuclear unit outages are discussed in Chapter 8)
- Hydro, 101
- Other, 18.

Within the overall cascade sequence, 29 (6%) generators tripped between the start of the cascade at 16:05:57 (the Sammis-Star trip) and the split between Ohio and Pennsylvania at 16:10:38.6 EDT (Erie West-Ashtabula-Perry), which triggered the first big power swing. These trips were caused by the generators' protective relays responding to overloaded transmission lines, so many of these trips were reported as under-voltage or overcurrent. The next interval in the cascade was as the portions of the grid lost synchronism, from 16:10:38.6 until 16:10:45.2 EDT, when Michigan-New York-Ontario-New England separated from the rest of the Eastern Interconnection. Fifty more generators (10%) tripped as the islands formed, particularly due to changes in configuration, loss of synchronism, excitation system failures, with some under-frequency and under-voltage. In the third phase of generator losses, 431 generators (84%) tripped after the islands formed, many at the same time that under-frequency load-shedding was occurring. This is illustrated in Figure 6.24. It is worth noting, however, that many generators did not trip instantly after the trigger condition that led to the trip—rather, many relay protective devices operate on time delays of milliseconds to seconds in duration, so that a generator that reported tripping at 16:10:43 on under-voltage or "generator protection" might have experienced the trigger for that condition several seconds earlier.

The high number of generators that tripped before formation of the islands helps to explain why so much of the northeast blacked out on August 14—many generators had pre-designed protection points that shut the unit down early in the cascade, so there were fewer units on-line to prevent island formation or to maintain balance between load and supply within each island after it formed. In particular, it appears that some generators tripped to protect the units from conditions that did not justify their protection, and many others were set to trip in ways that were not coordinated with the region's under-frequency load-shedding, rendering that UFLS scheme less effective. Both factors compromised successful islanding and precipitated the blackouts in Ontario and New York.

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Most of the unit separations fell in the category of consequential tripping—they tripped off-line in response to some outside condition on the grid, not because of any problem internal to the plant. Some generators became completely removed from all loads; because the fundamental operating principle of the grid is that load and generation must balance, if there was no load to be served the power plant shut down in response to over-speed and/or over-voltage protection schemes. Others were overwhelmed because they were among a few power plants within an electrical island, and were suddenly called on to serve huge customer loads, so the imbalance caused them to trip on under-frequency and/or under-voltage protection. A few were tripped by special protection schemes that activated on excessive frequency or loss of pre-studied major transmission elements known to require large blocks of generation rejection.

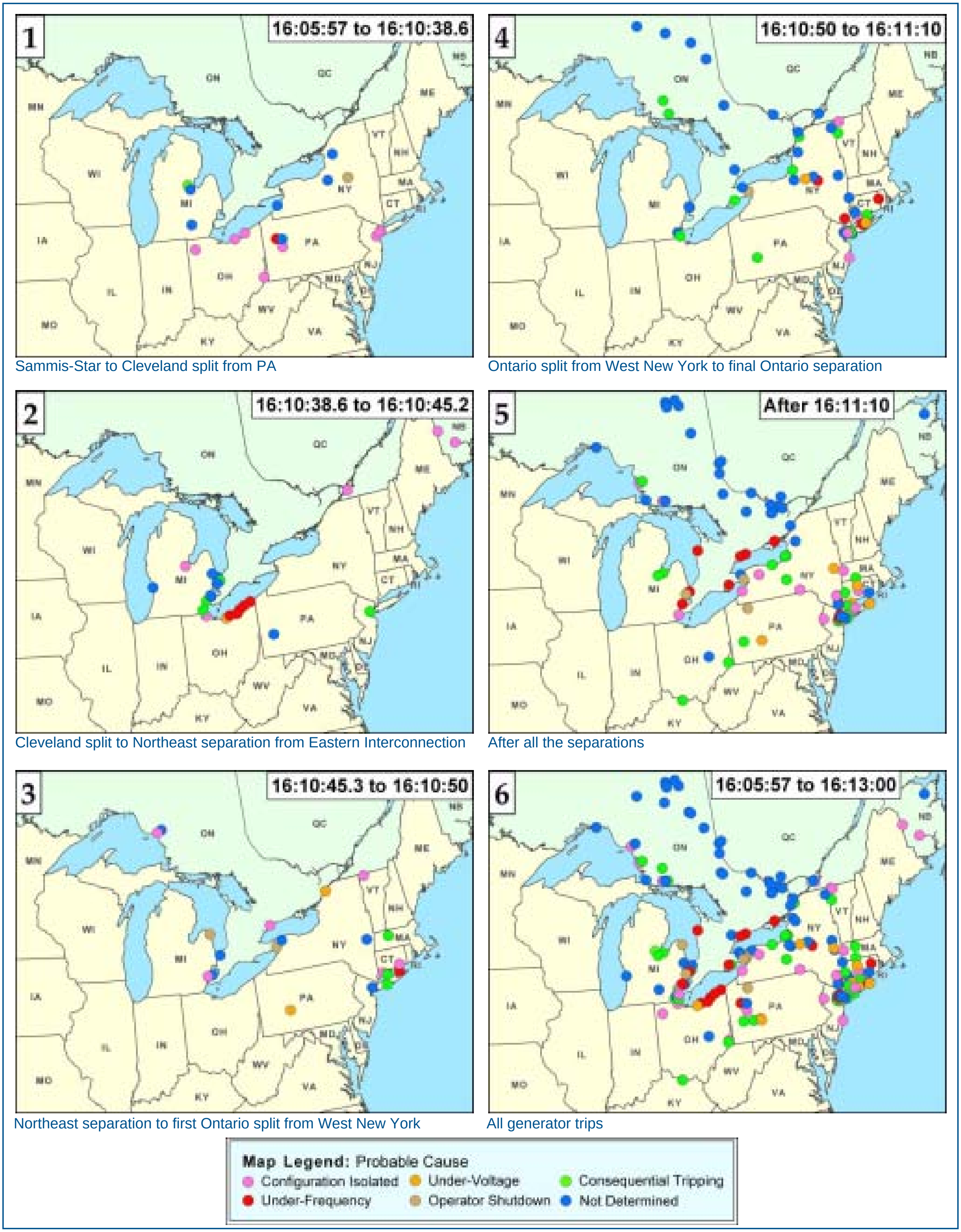
The large power swings and excursions of system frequency put all the units in their path through a sequence of major disturbances that shocked several units into tripping. Plant controls had actuated fast governor action on several of these to turn back the throttle, then turn it forward, only to turn it back again as some frequencies changed several times by as much as 3 Hz (about 100 times normal deviations). Figure 6.25 is a plot of the MW output and frequency for one large unit that nearly survived the disruption but tripped when in-plant hydraulic control pressure limits were eventually violated. After the plant control system called for shutdown, the turbine control valves closed and the generator electrical output ramped down to a preset value before the field excitation tripped and the generator breakers opened to disconnect the unit from the system. This also illustrates the time lag between system events and the generator reaction—this generator was first disturbed by system conditions at 16:10:37, but did not trip until 16:11:47, over a minute later.

Under-frequency (10% of the generators reporting) and under-voltage (6%) trips both reflect responses to system conditions. Although combustion turbines in particular are designed with under-voltage relay protection, it is not clear why this is needed. An under-voltage condition by itself and over a set time period may not necessarily be a generator hazard (although it could affect plant auxiliary systems). Some generator under-voltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%.

An excitation failure is closely related to a voltage trip. As local voltages decreased, so did frequency. Over-excitation operates on a calculation of volts/hertz, so as frequency declines faster than voltage over-excitation relays would operate. It is not clear that these relays were coordinated with each machine's exciter controls, to be sure that it was protecting the machine for the proper range of its control capabilities. Large units have two relays to detect volts/Hz—one at the generator and one at the transformer, each with a slightly different volts/Hz setting and time delay. It is possible that these settings can cause a generator to trip within a generation-deficient island as frequency is attempting to rebalance, so these settings should be carefully evaluated.

The Eastlake 5 trip at 13:31 EDT was an excitation system failure—as voltage fell at the generator bus, the generator tried to increase quickly its production of voltage on the AC winding of the machine quickly. This caused the generator's excitation protection scheme to trip the plant off to

Figure 6.24. Generator Trips by Time and Cause

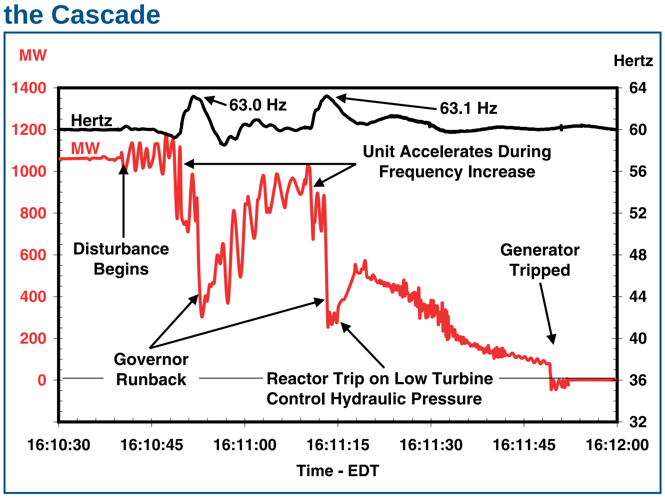


protect its windings and coils from over-heating. Several of the other generators which tripped early in the cascade came off under similar circumstances as excitation systems were over-stressed to hold voltages up. Seventeen generators reported tripping for over-excitation. Units that trip for a cause related to frequency should be evaluated to determine how the unit frequency triggers coordinate with the region's under-frequency load-shedding scheme, to assure that the generator trips are sequenced to follow rather than precede load-shedding. After UFLS operates to drop a large block of load, frequency continues to decline for several cycles before rebounding, so it is necessary to design an adequate time delay into generators' frequency-related protections to keep it on-line long enough to help rebalance against the remaining load.

Fourteen generators reported tripping for under-excitation (also known as loss of field), which protects the generator from exciter component failures. This protection scheme can operate on stable as well as transient power swings, so should be examined to determine whether the protection settings are appropriate. Eighteen units—primarily combustion turbines—reported over-current as the reason for relay operation.

Some generators in New York failed in a way that exacerbated frequency decay. A generator that tripped due to a boiler or steam problem may have done so to prevent damage due to over-speed and limit impact to the turbine-generator shaft when the breakers are opened, and it will attempt to maintain its synchronous speed until the generator is tripped. To do this, the mechanical part of the system would shut off the steam flow. This causes the generator to consume a small amount of power off the grid to support the unit's orderly slow-down and trip due to reverse power flow. This is a standard practice to avoid turbine over-speed. Also within New York, 16 gas turbines totaling about 400 MW reported tripping for loss of fuel supply, termed "flame out." These units' trips should be better understood.

Figure 6.25. Events at One Large Generator During the Cascade



Another reason for power plant trips was actions or failures of plant control systems. One common cause in this category was a loss of sufficient voltage to in-plant loads. Some plants run their internal cooling and processes (house electrical load) off the generator or off small, in-house auxiliary generators, while others take their power off the main grid. When large power swings or voltage drops reached these plants in the latter category, they tripped off-line because the grid could not supply the plant's in-house power needs reliably. At least 17 units reported tripping due to loss of system configuration, including the loss of a transmission or distribution line to serve the in-plant loads. Some generators were tripped by their operators.

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Unfortunately, 40% of the generators that went off-line during or after the cascade did not provide useful information on the cause of tripping in their response to the NERC investigation data request. While the responses available offer significant and valid information, the investigation team will never be able to fully analyze and explain why so many generators tripped off-line so early in the cascade, contributing to the speed and extent of the blackout. It is clear that every generator should have some minimum of protection for stator differential, loss of field, and out-of-step protection, to disconnect the unit from the grid when it is not performing correctly, and also protection for protect the generator from extreme conditions on the grid that could cause catastrophic damage to the generator. These protections should be set tight enough to protect the unit from the grid, but also wide enough to assure that the unit remains connected to the grid as long as possible. This coordination is a risk management issue that must balance the needs of the grid and customers relative to the needs of the individual assets.

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Key Phase 7 Events

Electric loads and flows do not respect political boundaries. After the blackout of 1965, as loads grew within New York City and neighboring northern New Jersey, the utilities serving the area deliberately increased the integration between the systems serving this area to increase the flow capability into New York and the reliability of the system as a whole. The combination of the facilities in place and the pattern of electrical loads and flows on August 14 caused New York to be tightly linked electrically to northern New Jersey and southwest Connecticut, and moved the weak spots on the grid out past this combined load and network area.

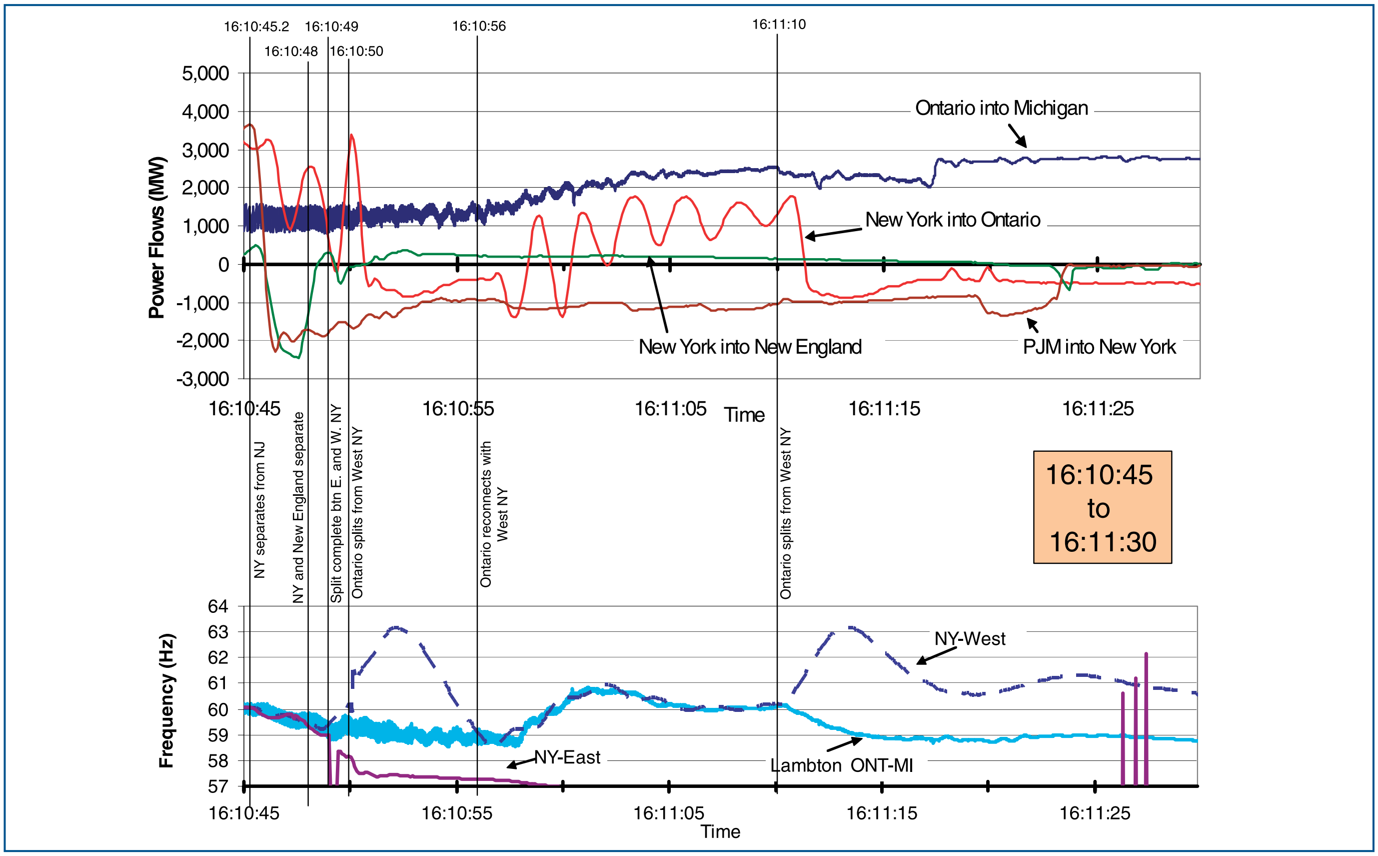
Figure 6.26 gives an overview of the power flows and frequencies in the period 16:10:45 EDT through 16:11:00 EDT, capturing most of the key events in Phase 7.

7A) New York-New England Transmission Lines Disconnected: 16:10:46 to 16:10:54 EDT

Over the period 16:10:46 EDT to 16:10:54 EDT, the separation between New England and New York occurred. It occurred along five of the northern tie lines, and seven lines within southwest Connecticut. At the time of the east-west separation in New York at 16:10:49 EDT, New England was isolated from the eastern New York island. The only remaining tie was the PV-20 circuit connecting New England and the western New York island, which tripped at 16:10:54 EDT. Because New England was exporting to New York before the disturbance across the southwest Connecticut tie, but importing on the Northwalk-Northport tie, the Pleasant Valley path opened east of Long Mountain—in other words, internal to southwest Connecticut—rather than along the actual New York-New England tie.[5] Immediately before the separation, the power swing out of New England occurred because the New England generators had increased output in response to the drag of power through Ontario and New York into Michigan and Ohio.[6] The power swings continuing through the region caused this separation, and caused Vermont to lose approximately 70 MW of load.

When the ties between New York and New England disconnected, most of the New England area along with Canada's Maritime Provinces (New Brunswick and Nova Scotia) became an island with generation and demand balanced close enough that it was able to remain operational. The New England system had been exporting close to

Figure 6.26. Measured Power Flows and Frequency Across Regional Interfaces, 16:10:45 to 16:11:30 EDT, with Key Events in the Cascade



600 MW to New York, so it was relatively generation-rich and experienced continuing fluctuations until it reached equilibrium. Before the Maritimes and New England separated from the Eastern Interconnection at approximately 16:11 EDT, voltages became depressed across portions of New England and some large customers disconnected themselves automatically.[7] However, southwestern Connecticut separated from New England and remained tied to the New York system for about one minute.

While frequency within New England wobbled slightly and recovered quickly after 16:10:40 EDT, frequency of the New York-Ontario-Michigan-Ohio island fluctuated severely as additional lines, loads and generators tripped, reflecting the severe generation deficiency in Michigan and Ohio.

Due to its geography and electrical characteristics, the Québec system in Canada is tied to the remainder of the Eastern Interconnection via high voltage DC (HVDC) links instead of AC transmission lines. Québec was able to survive the power surges with only small impacts because the DC connections shielded it from the frequency swings.

7B) New York Transmission Split East-West: 16:10:49 EDT

The transmission system split internally within New York along the Total East interface, with the eastern portion islanding to contain New York City, northern New Jersey, and southwestern Connecticut. The eastern New York island had been importing energy, so it did not have enough surviving generation on-line to balance load. Frequency declined quickly to below 58.0 Hz and triggered 7,115 MW of automatic UFLS.[8] Frequency declined further, as did voltage, causing pre-designed trips at the Indian Point nuclear plant and other generators in and around New York City through 16:11:10 EDT. The western portion of New York remained connected to Ontario and eastern Michigan.

The electric system has inherent weak points that vary as a function of the characteristics of the physical lines and plants and the topology of the lines, loads and flows across the grid at any point in time. The weakest points on a system tend to be those points with the highest impedance, which routinely are long (over 50 miles or 80 km) overhead lines with high loading. When such lines have high-speed relay protections that may trip on high current and overloads in addition to true faults, they will trip out before other lines in the path of large power swings such as the 3,500 MW power surge that hit New York on August 14. New York's Total East and Central East interfaces, where the internal split occurred, are routinely among the most heavily loaded paths in the state and are operated under thermal, voltage and stability limits to respect their relative vulnerability and importance.

Examination of the loads and generation in the Eastern New York island indicates before 16:10:00 EDT, the area had been importing electricity and had less generation on-line than load. At 16:10:50 EDT, seconds after the separation along the Total East interface, the eastern New York area had experienced significant load reductions due to under-frequency load-shedding—Consolidated Edison, which serves New York City and surrounding areas, dropped over 40% of its load on automatic UFLS. But at this time, the system was still experiencing dynamic conditions—as illustrated in Figure 6.26, frequency was falling, flows and voltages were oscillating, and power plants were tripping off-line.

Had there been a slow islanding situation and more generation on-line, it might have been possible for the Eastern New York island to rebalance given its high level of UFLS. But the available information indicates that events happened so quickly and the power swings were so large that rebalancing would have been unlikely, with or without the northern New Jersey and southwest Connecticut loads hanging onto eastern New York. This was further complicated because the high rate of change in voltages at load buses reduced the actual levels of load shed by UFLS relative to the levels needed and expected.

The team could not find any way that one electrical region might have protected itself against the August 14 blackout, either at electrical borders or internally. The team also looked at whether it was possible to design special protection schemes to separate one region from its neighborings proactively, to buffer itself from a power swing before it hit. This was found to be inadvisable for two reasons: (1) as noted above, the act of separation itself could cause oscillations and dynamic instability that could be as damaging to the system as the swing it was protecting against; and (2) there was no event or symptom on August 14 that could be used to trigger such a protection scheme in time.

7C) The Ontario System Just West of Niagara Falls and West of St. Lawrence Separated from the Western New York Island: 16:10:50 EDT

At 16:10:50 EDT, Ontario and New York separated west of the Ontario/New York interconnection, due to relay operations which disconnected nine 230-kV lines within Ontario. These left most of Ontario isolated to the north. Ontario's large Beck and Saunders hydro stations, along with some Ontario load, the New York Power Authority's (NYPA) Niagara and St. Lawrence hydro stations, and NYPA's 765-kV AC interconnection to their HVDC tie with Québec, remained connected to the western New York system, supporting the demand in upstate New York.

From 16:10:49 to 16:10:50 EDT, frequency in Ontario declined below 59.3 Hz, initiating automatic under-frequency load-shedding (3,000 MW). This load-shedding dropped about 12% of Ontario's remaining load. Between 16:10:50 EDT and 16:10:56 EDT, the isolation of Ontario's 2,300 MW Beck and Saunders hydro units onto the western New York island, coupled with under-frequency load-shedding in the western New York island, caused the frequency in this island to rise to 63.4 Hz due to excess generation relative to the load within the island (Figure 6.27). The high frequency caused trips of five of the U.S. nuclear units within the island, and the last one tripped on the second frequency rise.

Three of the tripped 230-kV transmission circuits near Niagara automatically reconnected Ontario to New York at 16:10:56 EDT by reclosing. Even with these lines reconnected, the main Ontario island (still attached to New York and eastern Michigan) was then extremely deficient in generation, so its frequency declined towards 58.8 Hz, the threshold for the second stage of under-frequency load-shedding. Within the next two seconds another 19% of Ontario demand (4,800 MW) automatically disconnected by under-frequency load-shedding. At 16:11:10 EDT, these same three lines tripped a second time west of Niagara, and New York and most of Ontario separated for a final time. Following this separation, the frequency in Ontario declined to 56 Hz by 16:11:57 EDT. With Ontario still supplying 2,500 MW to the Michigan-Ohio load pocket, the remaining ties with Michigan tripped at 16:11:57 EDT. Ontario system frequency declined, leading to a widespread shutdown at 16:11:58 EDT and the loss of 22,500 MW of load in Ontario, including the cities of Toronto, Hamilton, and Ottawa.

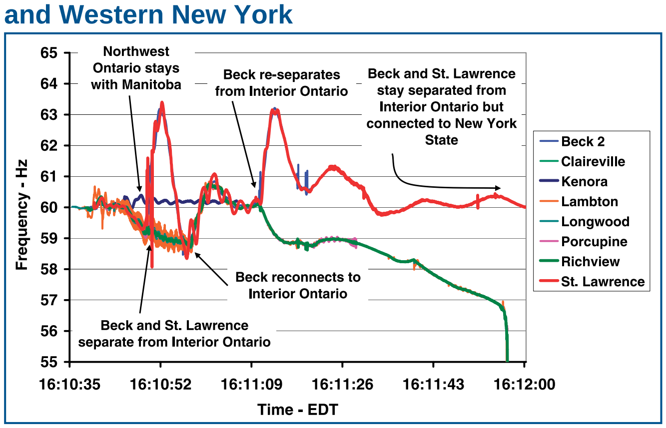
7D) Southwest Connecticut Separated from New York City: 16:11:22 EDT

In southwest Connecticut, when the Long Mountain-Plum Tree line (connected to the Pleasant Valley substation in New York) disconnected at 16:11:22 EDT, it left about 500 MW of southwest Connecticut demand supplied only through a 138-kV underwater tie to Long Island. About two seconds later, the two 345-kV circuits connecting southeastern New York to Long Island tripped, isolating Long Island and southwest Connecticut, which remained tied together by the underwater Norwalk Harbor-to-Northport 138-kV cable. The cable tripped about 20 seconds later, causing southwest Connecticut to black out.

Within the western New York island, the 345-kV system remained intact from Niagara east to the Utica area, and from the St. Lawrence/Plattsburgh area south to the Utica area through both the 765-kV and 230-kV circuits. Ontario's Beck and Saunders generation remained connected to New York at Niagara and St. Lawrence, respectively, and this island stabilized with about 50% of the pre-event load remaining. The boundary of this island moved southeastward as a result of the reclosure of Fraser-to-Coopers Corners 345-kV line at 16:11:23 EDT.

As a result of the severe frequency and voltage changes, many large generating units in New York and Ontario tripped off-line. The eastern island of New York, including the heavily populated areas of southeastern New York, New York City, and Long Island, experienced severe frequency and voltage declines. At 16:11:29 EDT, the New Scotland-to-Leeds 345-kV circuits tripped, separating the island into northern and southern sections. The small remaining load in the northern portion of the eastern island (the Albany area) retained

Figure 6.27. Frequency Separation Between Ontario and Western New York



electric service, supplied by local generation until it could be resynchronized with the western New York island.

7E) Remaining Transmission Lines Between Ontario and Eastern Michigan Separated: 16:11:57 EDT

Before the blackout, New England, New York, Ontario, eastern Michigan, and northern Ohio were scheduled net importers of power. When the western and southern lines serving Cleveland, Toledo, and Detroit collapsed, most of the load remained on those systems, but some generation had tripped. This exacerbated the generation/load imbalance in areas that were already importing power. The power to serve this load came through the only major path available, via Ontario (IMO). After most of IMO was separated from New York and generation to the north and east, much of the Ontario load and generation was lost; it took only moments for the transmission paths west from Ontario to Michigan to fail.

When the cascade was over at about 16:12 EDT, much of the disturbed area was completely blacked out, but there were isolated pockets that still had service because load and generation had reached equilibrium. Ontario’s large Beck and Saunders hydro stations, along with some Ontario load, the New York Power Authority’s (NYPA) Niagara and St. Lawrence hydro stations, and NYPA’s 765-kV AC interconnection to the Québec HVDC tie, remained connected to the western New York system, supporting demand in upstate New York.

Electrical islanding. Once the northeast became isolated, it lost more and more generation relative to load as more and more power plants tripped off-line to protect themselves from the growing disturbance. The severe swings in frequency and voltage in the area caused numerous lines to trip, so the isolated area broke further into smaller islands. The load/generation mismatch also affected voltages and frequency within these smaller areas, causing further generator trips and automatic under-frequency load-shedding, leading to blackout in most of these areas.

Figure 6.28 shows frequency data collected by the distribution-level monitors of Softswitching Technologies, Inc. (a commercial power quality company serving industrial customers) for the area affected by the blackout. The data reveal at least five separate electrical islands in the Northeast as the cascade progressed. The two paths of red diamonds on the frequency scale reflect the Albany area island (upper path) versus the New York City island, which declined and blacked out much earlier.

Cascading Sequence Essentially Complete: 16:13 EDT

Most of the Northeast (the area shown in gray in Figure 6.29) was now blacked out. Some isolated areas of generation and load remained on-line for several minutes. Some of those areas in which a close generation-demand balance could be maintained remained operational.

One relatively large island remained in operation serving about 5,700 MW of demand, mostly in western New York, anchored by the Niagara and St. Lawrence hydro plants. This island formed the basis for restoration in both New York and Ontario.

The entire cascade sequence is depicted graphically in Figure 6.30.

Figure 6.28. Electric Islands Reflected in Frequency Plot

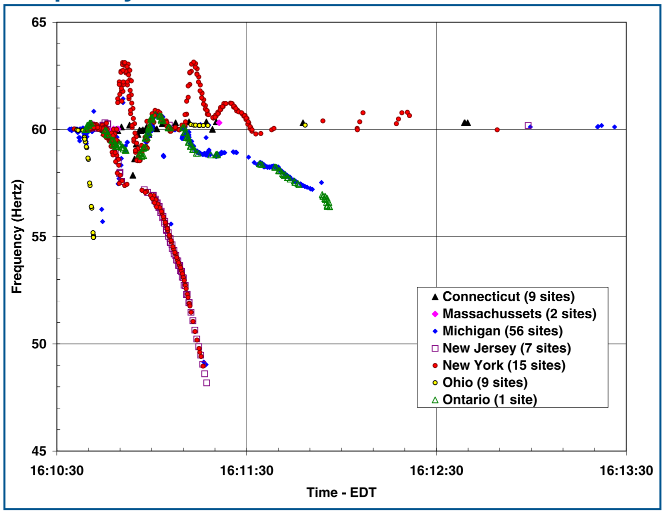


Figure 6.29. Area Affected by the Blackout

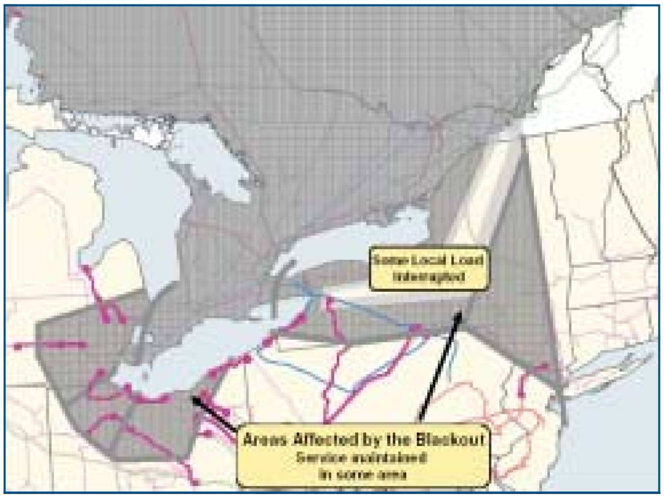
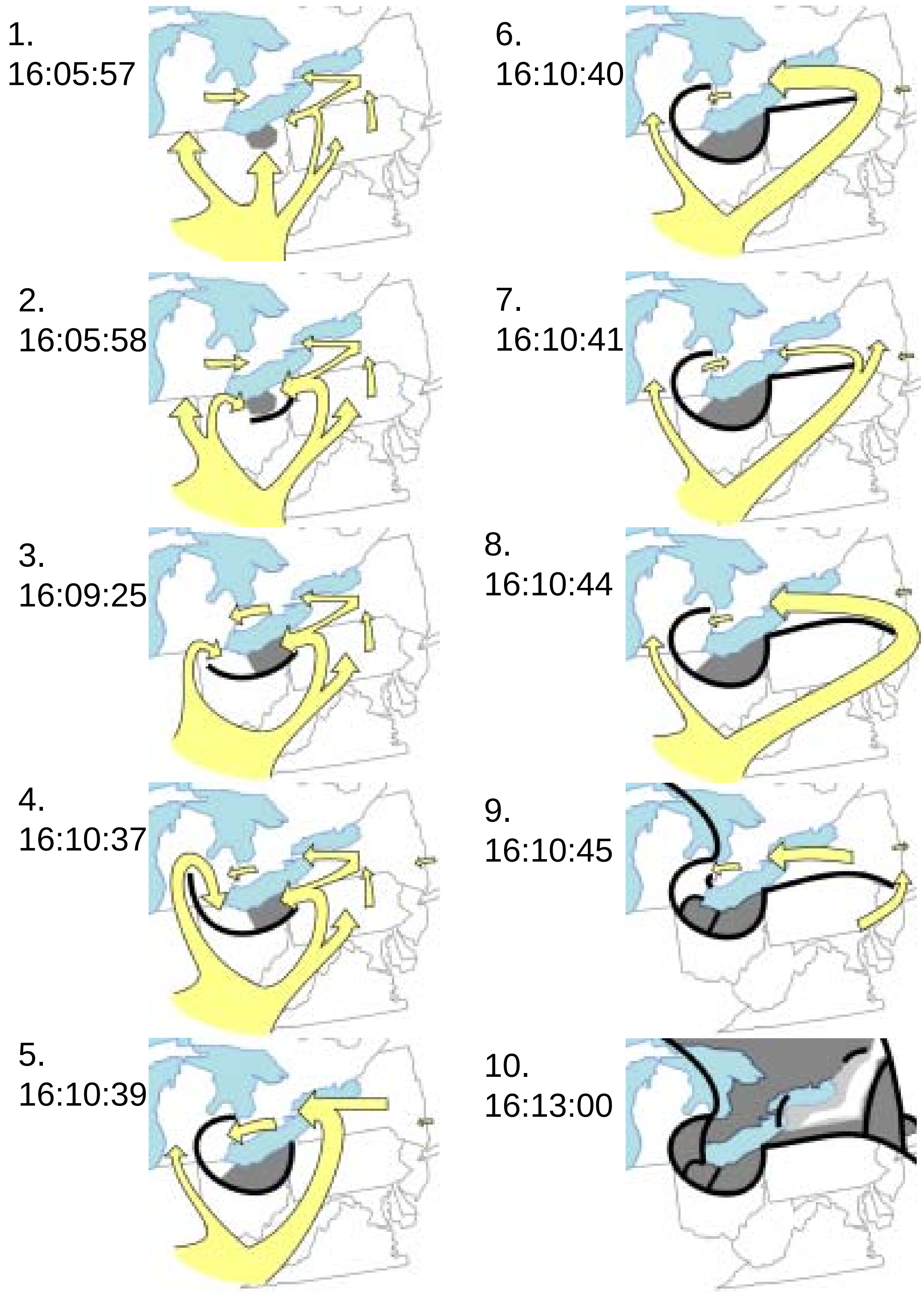


Figure 6.30. Cascade Sequence



Legend: Yellow arrows represent the overall pattern of electricity flows. Black lines represent approximate points of separation between areas within the Eastern Interconnect. Gray shading represents areas affected by the blackout.

Endnotes

[1] New York Independent System Operator, *Interim Report on the August 14, 2003 Blackout*, January 8, 2004, p. 14.

[2] *Ibid*., p. 14.

[3] These zone 2s are set on the 345-kV lines into the Argenta substation. The lines are owned by Michigan Electric Transmission Company and maintained by Consumers Power. Since the blackout occurred, Consumers Power has proactively changed the relay setting from 88 Ohms to 55 Ohms to reduce the reach of the relay. Source: Charles Rogers, Consumers Power.

[4] The province of Québec, although considered a part of the Eastern Interconnection, is connected to the rest of the Eastern Interconnection only by DC ties. In this instance, the DC ties acted as buffers between portions of the Eastern Interconnection; transient disturbances propagate through them less readily. Therefore, the electricity system in Québec was not affected by the outage, except for a small portion of the province's load that is directly connected to Ontario by AC transmission lines. (Although DC ties can act as a buffer between systems, the tradeoff is that they do not allow instantaneous generation support following the unanticipated loss of a generating unit.)

[5] New York Independent System Operator, *Interim Report on the August 14, 2003 Blackout*, January 8, 2004, p. 20.

[6] *Ibid*., p. 20.

[7] After New England's separation from the Eastern Interconnection occurred, the next several minutes were critical to stabilizing the ISO-NE system. Voltages in New England recovered and over-shot to high due to the combination of load loss, capacitors still in service, lower reactive losses on the transmission system, and loss of generation to regulate system voltage. Over-voltage protective relays operated to trip both transmission and distribution capacitors. Operators in New England brought all fast-start generation on-line by 16:16 EDT. Much of the customer process load was automatically restored. This caused voltages to drop again, putting portions of New England at risk of voltage collapse. Operators manually dropped 80 MW of load in southwest Connecticut by 16:39 EDT, another 325 MW in Connecticut and 100 MW in western Massachusetts by 16:40 EDT. These measures helped to stabilize their island following their separation from the rest of the Eastern Interconnection.

[8] New York Independent System Operator, *Interim Report on the August 14, 2003 Blackout*, January 8, 2004, p. 23.

7. The August 14 Blackout Compared With Previous Major North American Outages

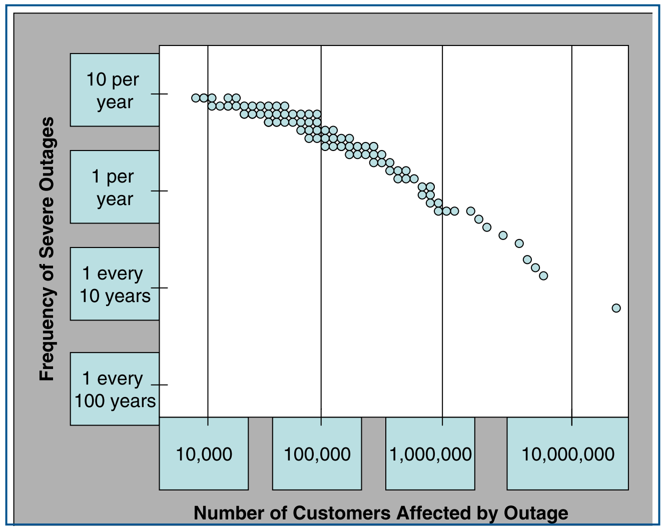
Incidence and Characteristics of Power System Outages

Short, localized outages occur on power systems fairly frequently. System-wide disturbances that affect many customers across a broad geographic area are rare, but they occur more frequently than a normal distribution of probabilities would predict. North American power system outages between 1984 and 1997 are shown in Figure 7.1 by the number of customers affected and the rate of occurrence. While some of these were widespread weather-related events, some were cascading events that, in retrospect, were preventable. Electric power systems are fairly robust and are capable of withstanding one or two contingency events, but they are fragile with respect to multiple contingency events unless the systems are readjusted between contingencies. With the shrinking margin in the current transmission system, it is likely to be more vulnerable to cascading outages than it was in the past, unless effective countermeasures are taken.

As evidenced by the absence of major transmission projects undertaken in North America over the past 10 to 15 years, utilities have found ways to increase the utilization of their existing facilities to meet increasing demands without adding significant high-voltage equipment. Without intervention, this trend is likely to continue. Pushing the system harder will undoubtedly increase reliability challenges. Special protection schemes may be relied on more to deal with particular challenges, but the system still will be less able to withstand unexpected contingencies.

A smaller transmission margin for reliability makes the preservation of system reliability a harder job than it used to be. The system is being operated closer to the edge of reliability than it was just a few years ago. Table 7.1 represents some of the changed conditions that make the preservation of reliability more challenging.

Figure 7.1. North American Power System Outages, 1984-1997



Note: The circles represent individual outages in North America between 1984 and 1997, plotted against the frequency of outages of equal or greater size over that period.

Source: Adapted from John Doyle, California Institute of Technology, "Complexity and Robustness," 1999. Data from NERC.

If nothing else changed, one could expect an increased frequency of large-scale events as compared to historical experience. The last and most extreme event shown in Figure 7.1 is the August 10, 1996, outage. August 14, 2003, surpassed that event in terms of severity. In addition, two significant outages in the month of September 2003 occurred abroad: one in England and one, initiated in Switzerland, that cascaded over much of Italy.

In the following sections, seven previous outages are reviewed and compared with the blackout of August 14, 2003: (1) Northeast blackout on November 9, 1965; (2) New York City blackout on July 13, 1977; (3) West Coast blackout on December 22, 1982; (4) West Coast blackout on July 2-3, 1996; (5) West Coast blackout on August 10, 1996; (6) Ontario and U.S. North Central blackout on June 25, 1998; and (7) Northeast outages and non-outage disturbances in the summer of 1999.

Outage Descriptions and Major Causal Factors

November 9, 1965: Northeast Blackout

This disturbance resulted in the loss of over 20,000 MW of load and affected 30 million people. Virtually all of New York, Connecticut, Massachusetts, Rhode Island, small segments of northern Pennsylvania and northeastern New Jersey, and substantial areas of Ontario, Canada, were affected. Outages lasted for up to 13 hours. This event resulted in the formation of the North American Electric Reliability Council in 1968.

A backup protective relay operated to open one of five 230-kV lines taking power north from a generating plant in Ontario to the Toronto area. When the flows redistributed instantaneously on the remaining four lines, they tripped out successively in a total of 2.5 seconds. The resultant power swings resulted in a cascading outage that blacked out much of the Northeast.

The major causal factors were as follows:

- Operation of a backup protective relay took a 230-kV line out of service when the loading on the line exceeded the 375-MW relay setting.
- Operating personnel were not aware of the operating set point of this relay.
- Another 230-kV line opened by an overcurrent relay action, and several 115- and 230-kV lines opened by protective relay action.
- Two key 345-kV east-west (Rochester-Syracuse) lines opened due to instability, and several lower voltage lines tripped open.
- Five of 16 generators at the St. Lawrence (Massena) plant tripped automatically in accordance with predetermined operating procedures.
- Following additional line tripouts, 10 generating units at Beck were automatically shut down by low governor oil pressure, and 5 pumping generators were tripped off by overspeed governor control.
- Several other lines then tripped out on under-frequency relay action.

July 13, 1977: New York City Blackout

This disturbance resulted in the loss of 6,000 MW of load and affected 9 million people in New York City. Outages lasted for up to 26 hours. A series of events triggering the separation of the Consolidated Edison system from neighboring systems and its subsequent collapse began when two 345-kV lines on a common tower in Northern Westchester were struck by lightning and tripped out. Over the next hour, despite Consolidated Edison dispatcher actions, the system electrically separated from surrounding systems and collapsed. With the loss of imports, generation in New York City was not sufficient to serve the load in the city.

Major causal factors were:

Table 7.1. Changing Conditions That Affect System Reliability

Previous Conditions	Emerging Conditions
Fewer, relatively large resources	Smaller, more numerous resources
Long-term, firm contracts	Contracts shorter in duration More non-firm transactions, fewer long-term firm transactions
Bulk power transactions relatively stable and predictable	Bulk power transactions relatively variable and less predictable
Assessment of system reliability made from stable base (narrower, more predictable range of potential operating states)	Assessment of system reliability made from variable base (wider, less predictable range of potential operating states)
Limited and knowledgable set of utility players	More players making more transactions, some with less interconnected operation experience; increasing with retail access
Unused transmission capacity and high security margins	High transmission utilization and operation closer to security limits
Limited competition, little incentive for reducing reliability investments	Utilities less willing to make investments in transmission reliability that do not increase revenues
Market rules and reliability rules developed together	Market rules undergoing transition, reliability rules developed separately
Limited wheeling	More system throughput

- Two 345-kV lines connecting Buchanan South to Millwood West experienced a phase B to ground fault caused by a lightning strike.
- Circuit breaker operations at the Buchanan South ring bus isolated the Indian Point No. 3 generating unit from any load, and the unit tripped for a rejection of 883 MW of load.
- Loss of the ring bus isolated the 345-kV tie to Ladentown, which had been importing 427 MW, making the cumulative resources lost 1,310 MW.
- 18.5 minutes after the first incident, an additional lightning strike caused the loss of two 345-kV lines, which connect Sprain Brook to Buchanan North and Sprain Brook to Millwood West. These two 345-kV lines share common towers between Millwood West and Sprain Brook. One line (Sprain Brook to Millwood West) automatically reclosed and was restored to service in about 2 seconds. The failure of the other line to reclose isolated the last Consolidated Edison interconnection to the Northwest.
- The resulting surge of power from the Northwest caused the loss of the Pleasant Valley to Millwood West line by relay action (a bent contact on one of the relays at Millwood West caused the improper action).
- 23 minutes later, the Leeds to Pleasant Valley 345-kV line sagged into a tree due to overload and tripped out.
- Within a minute, the 345 kV to 138 kV transformer at Pleasant Valley overloaded and tripped off, leaving Consolidated Edison with only three remaining interconnections.
- Within 3 minutes, the Long Island Lighting Co. system operator, on concurrence of the pool dispatcher, manually opened the Jamaica to Valley Stream tie.
- About 7 minutes later, the tap-changing mechanism failed on the Goethals phase-shifter, resulting in the loss of the Linden-to-Goethals tie to PJM, which was carrying 1,150 MW to Consolidated Edison.
- The two remaining external 138-kV ties to Consolidated Edison tripped on overload, isolating the Consolidated Edison system.
- Insufficient generation in the isolated system caused the Consolidated Edison island to collapse.

December 22, 1982: West Coast Blackout

This disturbance resulted in the loss of 12,350 MW of load and affected over 5 million people in the West. The outage began when high winds caused the failure of a 500-kV transmission tower. The tower fell into a parallel 500-kV line tower, and both lines were lost. The failure of these two lines mechanically cascaded and caused three additional towers to fail on each line. When the line conductors fell they contacted two 230-kV lines crossing under the 500-kV rights-of-way, collapsing the 230-kV lines.

The loss of the 500-kV lines activated a remedial action scheme to control the separation of the interconnection into two pre-engineered islands and trip generation in the Pacific Northwest in order to minimize customer outages and speed restoration. However, delayed operation of the remedial action scheme components occurred for several reasons, and the interconnection separated into four islands.

In addition to the mechanical failure of the transmission lines, analysis of this outage cited problems with coordination of protective schemes, because the generator tripping and separation schemes operated slowly or did not operate as planned. A communication channel component performed sporadically, resulting in delayed transmission of the control signal. The backup separation scheme also failed to operate, because the coordination of relay settings did not anticipate the power flows experienced in this severe disturbance.

In addition, the volume and format in which data were displayed to operators made it difficult to assess the extent of the disturbance and what corrective action should be taken. Time references to events in this disturbance were not tied to a common standard, making real-time evaluation of the situation more difficult.

July 2-3, 1996: West Coast Blackout

This disturbance resulted in the loss of 11,850 MW of load and affected 2 million people in the West. Customers were affected in Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming in the United States; Alberta and British Columbia in Canada; and Baja California Norte in Mexico. Outages lasted from a few minutes to several hours.

The outage began when a 345-kV transmission line in Idaho sagged into a tree and tripped out. A protective relay on a parallel transmission line also detected the fault and incorrectly tripped a second line. An almost simultaneous loss of these lines greatly reduced the ability of the system to transmit power from the nearby Jim Bridger plant. Other relays tripped two of the four generating units at that plant. With the loss of those two units, frequency in the entire Western Interconnection began to decline, and voltage began to collapse in the Boise, Idaho, area, affecting the California-Oregon AC Intertie transfer limit.

For 23 seconds the system remained in precarious balance, until the Mill Creek to Antelope 230-kV line between Montana and Idaho tripped by zone 3 relay, depressing voltage at Summer Lake Substation and causing the intertie to slip out of synchronism. Remedial action relays separated the system into five pre-engineered islands designed to minimize customer outages and restoration times. Similar conditions and initiating factors were present on July 3; however, as voltage began to collapse in the Boise area, the operator shed load manually and contained the disturbance.

August 10, 1996: West Coast Blackout

This disturbance resulted in the loss of over 28,000 MW of load and affected 7.5 million people in the West. Customers were affected in Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming in the United States; Alberta and British Columbia in Canada; and Baja California Norte in Mexico. Outages lasted from a few minutes to as long as nine hours.

Triggered by several major transmission line outages, the loss of generation from McNary Dam, and resulting system oscillations, the Western Interconnection separated into four electrical islands, with significant loss of load and generation. Prior to the disturbance, the transmission system from Canada south through the Northwest into California was heavily loaded with north-to-south power transfers. These flows were due to high Southwest demand caused by hot weather, combined with excellent hydroelectric conditions in Canada and the Northwest.

Very high temperatures in the Northwest caused two lightly loaded transmission lines to sag into untrimmed trees and trip out. A third heavily loaded line also sagged into a tree. Its outage led to the overload and loss of additional transmission lines. General voltage decline in the Northwest and the loss of McNary generation due to incorrectly applied relays caused power oscillations on the California to Oregon AC intertie. The intertie's protective relays tripped these facilities out and caused the Western Interconnection to separate into four islands. Following the loss of the first two lightly loaded lines, operators were unaware that the system was in an insecure state over the next hour, because new operating studies had not been performed to identify needed system adjustments.

June 25, 1998: Upper Midwest Blackout

This disturbance resulted in the loss of 950 MW of load and affected 152,000 people in Minnesota, Montana, North Dakota, South Dakota, and Wisconsin in the United States; and Ontario, Manitoba, and Saskatchewan in Canada. Outages lasted up to 19 hours.

A lightning storm in Minnesota initiated a series of events, causing a system disturbance that affected the entire Mid-Continent Area Power Pool (MAPP) Region and the northwestern Ontario Hydro system of the Northeast Power Coordinating Council. A 345-kV line was struck by lightning and tripped out. Underlying lower voltage lines began to overload and trip out, further weakening the system. Soon afterward, lightning struck a second 345-kV line, taking it out of service as well. Following the outage of the second 345-kV line, the remaining lower voltage transmission lines in the area became significantly overloaded, and relays took them out of service. This cascading removal of lines from service continued until the entire northern MAPP Region was separated from the Eastern Interconnection, forming three islands and resulting in the eventual blackout of the northwestern Ontario Hydro system.

Summer of 1999: Northeast U.S. Non-outage Disturbances

Load in the PJM system on July 6, 1999, was 51,600 MW (approximately 5,000 MW above forecast). PJM used all emergency procedures (including a 5% voltage reduction) except manually tripping load, and imported 5,000 MW from external systems to serve the record customer demand. Load on July 19, 1999, exceeded 50,500 MW. PJM loaded all available eastern PJM generation and again implemented emergency operating procedures from approximately 12 noon into the evening on both days.

During these record peak loads, steep voltage declines were experienced on the bulk transmission system. In each case, a voltage collapse was barely averted through the use of emergency procedures. Low voltage occurred because reactive demand exceeded reactive supply. High reactive demand was due to high electricity demand and high losses resulting from high transfers across the system. Reactive supply was inadequate because generators were unavailable or unable to meet rated reactive capability due to ambient conditions, and because some shunt capacitors were out of service.

Common or Similar Factors Among Major Outages

The factors that were common to some of the major outages above and the August 14 blackout include: (1) conductor contact with trees; (2) overestimation of dynamic reactive output of system generators; (3) inability of system operators or coordinators to visualize events on the entire system; (4) failure to ensure that system operation was within safe limits; (5) lack of coordination on system protection; (6) ineffective communication; (7) lack of "safety nets;" and (8) inadequate training of operating personnel. The following sections describe the nature of these factors and list recommendations from previous investigations that are relevant to each.

Conductor Contact With Trees

This factor was an initiating trigger in several of the outages and a contributing factor in the severity of several more. Unlike lightning strikes, for which system operators have fair storm-tracking tools, system operators generally do not have direct knowledge that a line has contacted a tree and faulted. They will sometimes test the line by trying to restore it to service, if that is deemed to be a safe operation. Even if it does go back into service, the line may fault and trip out again as load heats it up. This is most likely to happen when vegetation has not been adequately managed, in combination with hot and windless conditions.

In some of the disturbances, tree contact accounted for the loss of more than one circuit, contributing multiple contingencies to the weakening of the system. Lines usually sag into right-of-way obstructions when the need to retain transmission interconnection is high. High inductive load composition, such as air conditioning or irrigation pumping, accompanies hot weather and places higher burdens on transmission lines. Losing circuits contributes to voltage decline. Inductive load is unforgiving when voltage declines, drawing additional reactive supply from the system and further contributing to voltage problems.

Recommendations from previous investigations include:

- Paying special attention to the condition of rights-of-way following favorable growing seasons. Very wet and warm spring and summer growing conditions preceded the 1996 outages in the West.
- Careful review of any reduction in operations and maintenance expenses that may contribute to decreased frequency of line patrols or trimming. Maintenance in this area should be strongly directed toward preventive rather than remedial maintenance.

Dynamic Reactive Output of Generators

Reactive supply is an important ingredient in maintaining healthy power system voltages and facilitating power transfers. Inadequate reactive supply was a factor in most of the events. Shunt capacitors and generating resources are the most significant suppliers of reactive power. Operators perform contingency analysis based on how power system elements will perform under various power system conditions. They determine and set transfer limits based on these analyses. Shunt capacitors are easy to model because they are static. Modeling the dynamic reactive output of generators under stressed system conditions has proven to be more challenging. If the model is incorrect, estimated transfer limits will also be incorrect.

In most of the events, the assumed contribution of dynamic reactive output of system generators was greater than the generators actually produced, resulting in more significant voltage problems. Some generators were limited in the amount of reactive power they produced by over-excitation limits, or necessarily derated because of high ambient temperatures. Other generators were controlled to a fixed power factor and did not contribute reactive supply in depressed voltage conditions. Under-voltage load shedding is employed as an automatic remedial action in some interconnections to prevent cascading, and could be used more widely.

Recommendations from previous investigations concerning voltage support and reactive power management include:

- Communicate changes to generator reactive capability limits in a timely and accurate manner for both planning and operational modeling purposes.
- Investigate the development of a generator MVAr/voltage monitoring process to determine when generators may not be following reported MVAr limits.
- Establish a common standard for generator steady-state and post-contingency (15-minute) MVAr capability definition; determine methodology, testing, and operational reporting requirements.
- Determine the generator service level agreement that defines generator MVAr obligation to help ensure reliable operations.
- Periodically review and field test the reactive limits of generators to ensure that reported MVAr limits are attainable.
- Provide operators with on-line indications of available reactive capability from each generating unit or groups of generators, other VAr sources, and the reactive margin at all critical buses. This information should assist in the operating practice of maximizing the use of shunt capacitors during heavy transfers and thereby increase the availability of system dynamic reactive reserve.
- For voltage instability problems, consider fast automatic capacitor insertion (both series and shunt), direct shunt reactor and load tripping, and under-voltage load shedding.
- Develop and periodically review a reactive margin against which system performance should be evaluated and used to establish maximum transfer levels.

System Visibility Procedures and Operator Tools

Each control area operates as part of a single synchronous interconnection. However, the parties with various geographic or functional responsibilities for reliable operation of the grid do not have visibility of the entire system. Events in neighboring systems may not be visible to an operator or reliability coordinator, or power system data may be available in a control center but not be presented to operators or coordinators as information they can use in making appropriate operating decisions.

Recommendations from previous investigations concerning visibility and tools include:

- Develop communications systems and displays that give operators immediate information on changes in the status of major components in their own and neighboring systems.
- Supply communications systems with uninterruptible power, so that information on system conditions can be transmitted correctly to control centers during system disturbances.
- In the control center, use a dynamic line loading and outage display board to provide operating personnel with rapid and comprehensive information about the facilities available and the operating condition of each facility in service.
- Give control centers the capability to display to system operators computer-generated alternative actions specific to the immediate situation, together with expected results of each action.
- Establish on-line security analysis capability to identify those next and multiple facility outages that would be critical to system reliability from thermal, stability, and post-contingency voltage points of view.
- Establish time-synchronized disturbance monitoring to help evaluate the performance of the interconnected system under stress, and design appropriate controls to protect it.

System Operation Within Safe Limits

Operators in several of the events were unaware of the vulnerability of the system to the next contingency. The reasons were varied: inaccurate modeling for simulation, no visibility of the loss of key transmission elements, no operator monitoring of stability measures (reactive reserve monitor, power transfer angle), and no reassessment of system conditions following the loss of an element and readjustment of safe limits.

Recommendations from previous investigations include:

- Following a contingency, the system must be returned to a reliable state within the allowed readjustment period. Operating guides must be reviewed to ensure that procedures exist to restore system reliability in the allowable time periods.

- ◆ Reduce scheduled transfers to a safe and prudent level until studies have been conducted to determine the maximum simultaneous transfer capability limits.
- ◆ Reevaluate processes for identifying unusual operating conditions and potential disturbance scenarios, and make sure they are studied before they are encountered in real-time operating conditions.

Coordination of System Protection (Transmission and Generation Elements)

Protective relays are designed to detect short circuits and act locally to isolate faulted power system equipment from the system—both to protect the equipment from damage and to protect the system from faulty equipment. Relay systems are applied with redundancy in primary and backup modes. If one relay fails, another should detect the fault and trip appropriate circuit breakers. Some backup relays have significant "reach," such that non-faulted line overloads or stable swings may be seen as faults and cause the tripping of a line when it is not advantageous to do so. Proper coordination of the many relay devices in an interconnected system is a significant challenge, requiring continual review and revision. Some relays can prevent resynchronizing, making restoration more difficult.

System-wide controls protect the interconnected operation rather than specific pieces of equipment. Examples include controlled islanding to mitigate the severity of an inevitable disturbance and under-voltage or under-frequency load shedding. Failure to operate (or misoperation of) one or more relays as an event developed was a common factor in several of the disturbances.

Recommendations developed after previous outages include:

- ◆ Perform system trip tests of relay schemes periodically. At installation the acceptance test should be performed on the complete relay scheme in addition to each individual component so that the adequacy of the scheme is verified.
- ◆ Continually update relay protection to fit changing system development and to incorporate improved relay control devices.
- ◆ Install sensing devices on critical transmission lines to shed load or generation automatically if the short-term emergency rating is exceeded for a specified period of time. The time delay should be long enough to allow the system operator to attempt to reduce line loadings promptly by other means.
- ◆ Review phase-angle restrictions that can prevent reclosing of major interconnections during system emergencies. Consideration should be given to bypassing synchronism-check relays to permit direct closing of critical interconnections when it is necessary to maintain stability of the grid during an emergency.
- ◆ Review the need for controlled islanding. Operating guides should address the potential for significant generation/load imbalance within the islands.

Effectiveness of Communications

Under normal conditions, parties with reliability responsibility need to communicate important and prioritized information to each other in a timely way, to help preserve the integrity of the grid. This is especially important in emergencies. During emergencies, operators should be relieved of duties unrelated to preserving the grid. A common factor in several of the events described above was that information about outages occurring in one system was not provided to neighboring systems.

Need for Safety Nets

A safety net is a protective scheme that activates automatically if a pre-specified, significant contingency occurs. When activated, such schemes involve certain costs and inconvenience, but they can prevent some disturbances from getting out of control. These plans involve actions such as shedding load, dropping generation, or islanding, and in all cases the intent is to have a controlled outcome that is less severe than the likely uncontrolled outcome. If a safety net had not been taken out of service in the West in August 1996, it would have lessened the severity of the disturbance from 28,000 MW of load lost to less than 7,200 MW. (It has since been returned to service.) Safety nets should not be relied upon to establish transfer limits, however.

Previous recommendations concerning safety nets include:

- ◆ Establish and maintain coordinated programs of automatic load shedding in areas not so equipped, in order to prevent total loss of power in an area that has been separated from the main network and is deficient in generation. Load shedding should be regarded as an insurance program, however, and should not be used as a substitute for adequate system design.

- Install load-shedding controls to allow fast single-action activation of large-block load shedding by an operator.

Training of Operating Personnel

Operating procedures were necessary but not sufficient to deal with severe power system disturbances in several of the events. Enhanced procedures and training for operating personnel were recommended. Dispatcher training facility scenarios with disturbance simulation were suggested as well. Operators tended to reduce schedules for transactions but were reluctant to call for increased generation—or especially to shed load—in the face of a disturbance that threatened to bring the whole system down.

Previous recommendations concerning training include:

- Thorough programs and schedules for operator training and retraining should be vigorously administered.
- A full-scale simulator should be made available to provide operating personnel with "hands-on" experience in dealing with possible emergency or other system conditions.
- Procedures and training programs for system operators should include anticipation, recognition, and definition of emergency situations.
- Written procedures and training materials should include criteria that system operators can use to recognize signs of system stress and mitigating measures to be taken before conditions degrade into emergencies.
- Line loading relief procedures should not be relied upon when the system is in an insecure state, as these procedures cannot be implemented effectively within the required time frames in many cases. Other readjustments must be used, and the system operator must take responsibility to restore the system immediately.
- Operators' authority and responsibility to take immediate action if they sense the system is starting to degrade should be emphasized and protected.
- The current processes for assessing the potential for voltage instability and the need to enhance the existing operator training programs, operational tools, and annual technical assessments should be reviewed to improve the ability to predict future voltage stability problems prior to their occurrence, and to mitigate the potential for adverse effects on a regional scale.

Comparisons With the August 14 Blackout

The blackout on August 14, 2003, had several causes or contributory factors in common with the earlier outages, including:

- Inadequate vegetation management
- Failure to ensure operation within secure limits
- Failure to identify emergency conditions and communicate that status to neighboring systems
- Inadequate operator training
- Inadequate regional-scale visibility over the power system
- Inadequate coordination of relays and other protective devices or systems.

New causal features of the August 14 blackout include: inadequate interregional visibility over the power system; dysfunction of a control area's SCADA/EMS system; and lack of adequate backup capability to that system.

8. Performance of Nuclear Power Plants Affected by the Blackout

Introduction

On August 14, 2003, nine U.S. nuclear power plants experienced rapid shutdowns (reactor trips) as a consequence of the power outage. Seven nuclear power plants in Canada operating at high power levels at the time of the event also experienced rapid shutdowns. Four other Canadian nuclear plants automatically disconnected from the grid due to the electrical transient but were able to continue operating at a reduced power level and were available to supply power to the grid as it was restored by the transmission system operators. Six nuclear plants in the United States and one in Canada experienced significant electrical disturbances but were able to continue generating electricity. Many non-nuclear generating plants in both countries also tripped during the event. Numerous other nuclear plants observed disturbances on the electrical grid but continued to generate electrical power without interruption.

The Nuclear Working Group (NWG) was one of three Working Groups created to support the U.S.-Canada Power System Outage Task Force. The NWG was charged with identifying all relevant actions by nuclear generating facilities in connection with the outage. Nils Diaz, Chairman of the U.S. Nuclear Regulatory Commission (NRC) and Linda Keen, President and CEO of the Canadian Nuclear Safety Commission (CNSC) were co-chairs of the Working Group, with other members appointed from industry and various State and federal agencies.

In Phase I, the NWG focused on collecting and analyzing data from each affected nuclear power plant to determine what happened, and whether any activities at the plants caused or contributed to the power outage or involved a significant safety issue. Phase I culminated in the issuance of the Task Force's *Interim Report*, which reported that:

- The affected nuclear power plants did not trigger the power outage or inappropriately contribute to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions).
- The severity of the grid transient caused generators, turbines, or reactor systems at the nuclear plants to reach protective feature limits and actuate automatic protective actions.
- The nuclear plants responded to the grid conditions in a manner consistent with the plant designs.
- The nuclear plants were maintained in a safe condition until conditions were met to permit the nuclear plants to resume supplying electrical power to the grid.
- **For nuclear plants in the United States:**
  - Fermi 2, Oyster Creek, and Perry tripped due to main generator trips, which resulted from voltage and frequency fluctuations on the grid. Nine Mile 1 tripped due to a main turbine trip due to frequency fluctuations on the grid.
  - FitzPatrick and Nine Mile 2 tripped due to reactor trips, which resulted from turbine control system low pressure due to frequency fluctuations on the grid. Ginna tripped due to a reactor trip which resulted from a large loss of electrical load due to frequency fluctuations on the grid. Indian Point 2 and Indian Point 3 tripped due to a reactor trip on low flow, which resulted when low grid frequency tripped reactor coolant pumps.
- **For nuclear plants in Canada:**
  - At Bruce B and Pickering B, frequency and/or voltage fluctuations on the grid resulted in the automatic disconnection of generators from the grid. For those units that were successful in maintaining the unit generators operational, reactor power was automatically reduced.

- ➢ At Darlington, load swing on the grid led to the automatic reduction in power of the four reactors. The generators were, in turn, automatically disconnected from the grid.
- ➢ Three reactors at Bruce B and one at Darlington were returned to 60% power. These reactors were available to deliver power to the grid on the instructions of the transmission system operator.
- ➢ Three units at Darlington were placed in a zero-power hot state, and four units at Pickering B and one unit at Bruce B were placed in a Guaranteed Shutdown State.

The licensees' return to power operation followed a deliberate process controlled by plant procedures and regulations. Equipment and process problems, whether existing prior to or caused by the event, would normally be addressed prior to restart. The NWG is satisfied that licensees took an appropriately conservative approach to their restart activities, placing a priority on safety.

- ◆ **For U.S. nuclear plants:** Ginna, Indian Point 2, Nine Mile 2, and Oyster Creek resumed electrical generation on August 17. FitzPatrick and Nine Mile 1 resumed electrical generation on August 18. Fermi 2 resumed electrical generation on August 20. Perry resumed electrical generation on August 21. Indian Point 3 resumed electrical generation on August 22. Indian Point 3 had equipment issues (failed splices in the control rod drive mechanism power system) that required repair prior to restart. Ginna submitted a special request for enforcement discretion from the NRC to permit mode changes and restart with an inoperable auxiliary feedwater pump. The NRC granted the request for enforcement discretion.
- ◆ **For Canadian nuclear plants:** The restart of the Canadian nuclear plants was carried out in accordance with approved Operating Policies and Principles. Three units at Bruce B and one at Darlington were resynchronized with the grid within 6 hours of the event. The remaining three units at Darlington were reconnected by August 17 and 18. Units 5, 6, and 8 at Pickering B and Unit 6 at Bruce B returned to service between August 22 and August 25.

The NWG has found no evidence that the shutdown of the nuclear power plants triggered the outage or inappropriately contributed to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions). All the nuclear plants that shut down or disconnected from the grid responded automatically to grid conditions. All the nuclear plants responded in a manner consistent with the plant designs. Safety functions were effectively accomplished, and the nuclear plants that tripped were maintained in a safe shutdown condition until their restart.

In Phase II, the NWG collected comments and analyzed information related to potential recommendations to help prevent future power outages. Representatives of the NWG, including representatives of the NRC and the CNSC, attended public meetings to solicit feedback and recommendations held in Cleveland, Ohio; New York City, New York; and Toronto, Ontario, on December 4, 5, and 8, 2003, respectively. Representatives of the NWG also participated in the NRC's public meeting to solicit feedback and recommendations on the Northeast blackout held in Rockville, Maryland, on January 6, 2004.

Additional details on both the Phase I and Phase II efforts are available in the following sections. Due to the major design differences between nuclear plants in Canada and the United States, the NWG decided to have separate sections for each country. This also responds to the request by the nuclear regulatory agencies in both countries to have sections of the report that stand alone, so that they can also be used as regulatory documents.

Findings of the U.S. Nuclear Working Group

Summary

The U.S. NWG found no evidence that the shutdown of the nine U.S. nuclear power plants triggered the outage, or inappropriately contributed to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions). All nine plants that experienced a reactor trip were responding to grid conditions. The severity of the grid transient caused generators, turbines, or reactor systems at the plants to reach a protective feature limit and actuate a plant shutdown. All nine plants tripped in response to those conditions in a manner consistent with the plant designs. The nine plants automatically shut down in a safe fashion to protect the plants from the grid transient. Safety functions were effectively accomplished with few problems, and the plants were maintained in a safe shutdown condition until their restart.

The nuclear power plant outages that resulted from the August 14, 2003, power outage were triggered by automatic protection systems for the reactors or turbine-generators, not by any manual operator actions. The NWG has received no information that points to operators deliberately shutting down nuclear units to isolate themselves from instabilities on the grid. In short, only automatic separation of nuclear units occurred.

Regarding the 95 other licensed commercial nuclear power plants in the United States: 4 were already shut down at the time of the power outage, one of which experienced a grid disturbance; 70 operating plants observed some level of grid disturbance but accommodated the disturbances and remained on line, supplying power to the grid; and 21 operating plants did not experience any grid disturbance.

Introduction

The NRC, which regulates U.S. commercial nuclear power plants, has regulatory requirements for offsite power systems. These requirements address the number of offsite power sources and the ability to withstand certain transients. Offsite power is the normal source of alternating current (AC) power to the safety systems in the plants when the plant main generator is not in operation. The requirements also are designed to protect safety systems from potentially damaging variations (in voltage and frequency) in the supplied power. For loss of offsite power events, the NRC requires emergency generation (typically emergency diesel generators) to provide AC power to safety systems. In addition, the NRC provides oversight of the safety aspects of offsite power issues through its inspection program, by monitoring operating experience, and by performing technical studies.

Phase I: Fact Finding

Phase I of the NWG effort focused on collecting and analyzing data from each plant to determine what happened, and whether any activities at the plants caused or contributed to the power outage or its spread or involved a significant safety issue. To ensure accuracy, comprehensive coordination was maintained among the working group members and among the NWG, ESWG, and SWG.

The staff developed a set of technical questions to obtain data from the owners or licensees of the nuclear power plants that would enable them to review the response of the nuclear plant systems in detail. Two additional requests for more specific information were made for certain plants. The collection of information from U.S. nuclear power plants was gathered through the NRC regional offices, which had NRC resident inspectors at each plant obtain licensee information to answer the questions. General design information was gathered from plant-specific Updated Final Safety Analysis Reports and other documents.

Plant data were compared against plant designs by the NRC staff to determine whether the plant responses were as expected; whether they appeared to cause the power outage or contributed to the spread of the outage; and whether applicable safety requirements were met. In some cases supplemental questions were developed, and answers were obtained from the licensees to clarify the observed response of the plant. The NWG interfaced with the ESWG to validate some data and to obtain grid information, which contributed to the analysis. The NWG identified relevant actions by nuclear generating facilities in connection with the power outage.

Typical Design, Operational, and Protective Features of U.S. Nuclear Power Plants

Nuclear power plants have a number of design, operational, and protective features to ensure that the plants operate safely and reliably. This section describes these features so as to provide a better understanding of how nuclear power plants interact with the grid and, specifically, how nuclear power plants respond to changing grid conditions. While the features described in this section are typical, there are differences in the design and operation of individual plants which are not discussed.

Design Features of U.S. Nuclear Power Plants

Nuclear power plants use heat from nuclear reactions to generate steam and use a single steam-driven turbine-generator (also known as the main generator) to produce electricity supplied to the grid.

Connection of the plant switchyard to the grid. The plant switchyard normally forms the interface between the plant main generator and the electrical grid. The plant switchyard has multiple transmission lines connected to the grid system to meet offsite power supply requirements for having reliable offsite power for the nuclear station under all operating and shutdown conditions. Each transmission line connected to the switchyard has dedicated circuit breakers, with fault sensors, to isolate faulted conditions in the switchyard or the connected transmission lines, such as phase-to-phase or phase-to-ground short circuits. The fault sensors are fed into a protection scheme for the plant switchyard that is engineered to localize any faulted conditions with minimum system disturbance.

Connection of the main generator to the switchyard. The plant main generator produces electrical power and transmits that power to the offsite transmission system. Most plants also supply power to the plant auxiliary buses for normal operation of the nuclear generating unit through the unit auxiliary transformer. During normal plant operation, the main generator typically generates electrical power at about 22 kV. The voltage is increased to match the switchyard voltage by the main transformers, and the power flows to the high voltage switchyard through two power circuit breakers.

Power supplies for the plant auxiliary buses. The safety-related and nonsafety auxiliary buses are normally lined up to receive power from the main generator auxiliary transformer, although some plants leave some of their auxiliary buses powered from a startup transformer (that is, from the offsite power distribution system). When plant power generation is interrupted, the power supply automatically transfers to the offsite power source (the startup transformer). If that is not supplying acceptable voltage, the circuit breakers to the safety-related buses open, and the buses are reenergized by the respective fast-starting emergency diesel generators. The nonsafety auxiliary buses will remain deenergized until offsite power is restored.

Operational Features of U.S. Nuclear Power Plants

Response of nuclear power plants to changes in switchyard voltage. With the main generator voltage regulator in the automatic mode, the generator will respond to an increase of switchyard voltage by reducing the generator field excitation current. This will result in a decrease of reactive power, normally measured as mega-volts-amperes-reactive (MVAr) from the generator to the switchyard and out to the surrounding grid, helping to control the grid voltage increase. With the main generator voltage regulator in the automatic mode, the generator will respond to a decrease of switchyard voltage by increasing the generator field excitation current. This will result in an increase of reactive power (MVAr) from the generator to the switchyard and out to the surrounding grid, helping to control the grid voltage decrease. If the switchyard voltage goes low enough, the increased generator field current could result in generator field overheating. Over-excitation protective circuitry is generally employed to prevent this from occurring. This protective circuitry may trip the generator to prevent equipment damage.

Under-voltage protection is provided for the nuclear power plant safety buses, and may be provided on nonsafety buses and at individual pieces of equipment. It is also used in some pressurized water reactor designs on reactor coolant pumps (RCPs) as an anticipatory loss of RCP flow signal.

Protective Features of U.S. Nuclear Power Plants

The main generator and main turbine have protective features, similar to fossil generating stations, which protect against equipment damage. In general, the reactor protective features are designed to protect the reactor fuel from damage and to protect the reactor coolant system from over-pressure or over-temperature transients. Some trip features also produce a corresponding trip in other components; for example, a turbine trip typically results in a reactor trip above a low power setpoint.

Generator protective features typically include over-current, ground detection, differential relays (which monitor for electrical fault conditions within a zone of protection defined by the location of the sensors, typically the main generator and all transformers connected directly to the generator output), electrical faults on the transformers connected to the generator, loss of the generator field, and a turbine trip. Turbine protective features typically include over-speed (usually set at 1980 rpm or 66 Hz), low bearing oil pressure, high bearing vibration, degraded condenser vacuum, thrust bearing failure, or generator trip. Reactor protective features typically include trips for over-power, abnormal pressure in the reactor coolant system, low reactor coolant system flow, low level in the steam generators or the reactor vessel, or a trip of the turbine.

Considerations on Returning a U.S. Nuclear Power Plant to Power Production After Switchyard Voltage Is Restored

The following are examples of the types of activities that must be completed before returning a nuclear power plant to power production following a loss of switchyard voltage.

- Switchyard voltage must be normal and stable from an offsite supply. Nuclear power plants are not designed for black-start capability (the ability to start up without external power).
- Plant buses must be energized from the switchyard and the emergency diesel generators restored to standby mode.
- Normal plant equipment, such as reactor coolant pumps and circulating water pumps, must be restarted.
- A reactor trip review report must be completed and approved by plant management, and the cause of the trip must be addressed.
- All plant technical specifications must be satisfied. Technical specifications are issued to each nuclear power plant as part of their license by the NRC. They dictate equipment which must be operable and process parameters which must be met to allow operation of the reactor. Examples of actions that were required following the events of August 14 include refilling the diesel fuel oil storage tanks, refilling the condensate storage tanks, establishing reactor coolant system forced flow, and cooling the suppression pool to normal operating limits. Surveillance tests must be completed as required by technical specifications (for example, operability of the low-range neutron detectors must be demonstrated).
- Systems must be aligned to support the startup.
- Pressures and temperatures for reactor startup must be established in the reactor coolant system for pressurized water reactors.
- A reactor criticality calculation must be performed to predict the control rod withdrawals needed to achieve criticality, where the fission chain reaction becomes self-sustaining due to the increased neutron flux. Certain neutron-absorbing fission products increase in concentration following a reactor trip (followed later by a decrease or decay). At pressurized water reactors, the boron concentration in the primary coolant must be adjusted to match the criticality calculation. Near the end of the fuel cycle, the nuclear power plant may not have enough boron adjustment or control rod worth available for restart until the neutron absorbers have decreased significantly (more than 24 hours after the trip).

It may require a day or more before a nuclear power plant can restart following a normal trip. Plant trips are a significant transient on plant equipment, and some maintenance may be necessary before the plant can restart. When combined with the infrequent event of loss of offsite power, additional recovery actions will be required. Safety systems, such as emergency diesel generators and safety-related decay heat removal systems, must be restored to normal lineups. These additional actions would extend the time necessary to restart a nuclear plant from this type of event.

Summary of U.S. Nuclear Power Plant Response to and Safety During the August 14 Outage

The NWG's review did not identify any activity or equipment issues at U.S. nuclear power plants that caused the transient on August 14, 2003. Nine nuclear power plants tripped within about 60 seconds as a result of the grid disturbance. Additionally, many nuclear power plants experienced a transient due to this grid disturbance.

Nuclear Power Plants That Tripped

The trips at nine nuclear power plants resulted from the plant responses to the grid disturbances. Following the initial grid disturbances, voltages in the plant switchyard fluctuated and reactive power flows fluctuated. As the voltage regulators on the main generators attempted to compensate, equipment limits were exceeded and protective trips resulted. This happened at Fermi 2 and Oyster Creek. Fermi 2 tripped on a generator field protection trip. Oyster Creek tripped due to a generator trip on high ratio of voltage relative to the electrical frequency.

Also, as the balance between electrical generation and electrical load on the grid was disturbed, the electrical frequency began to fluctuate. In some cases the electrical frequency dropped low enough to actuate protective features. This happened at Indian Point 2, Indian Point 3, and Perry. Perry tripped due to a generator under-frequency trip signal. Indian Point 2 and Indian Point 3 tripped when the grid frequency dropped low enough to trip reactor coolant pumps, which actuated a reactor protective feature.

In other cases, the electrical frequency fluctuated and went higher than normal. Turbine control systems responded in an attempt to control the frequency. Equipment limits were exceeded as a result of the reaction of the turbine control systems to large frequency changes. This led to trips at FitzPatrick, Nine Mile 1, Nine Mile 2, and Ginna. FitzPatrick and Nine Mile 2 tripped on low pressure in the turbine hydraulic control oil system. Nine Mile 1 tripped on turbine light load protection. Ginna tripped due to conditions in the reactor following rapid closure of the turbine control valves in response to high frequency on the grid.

The Perry, Fermi 2, Oyster Creek, and Nine Mile 1 reactors tripped immediately after the generator tripped, although that is not apparent from the times below, because the clocks were not synchronized to the national time standard. The Indian Point 2 and 3, FitzPatrick, Ginna, and Nine Mile 2 reactors tripped before the generators. When the reactor trips first, there is generally a short time delay before the generator output breakers open. The electrical generation decreases rapidly to zero after the reactor trip. Table 8.1 provides the times from the data collected for the reactor trip times, and the time the generator output breakers opened (generator trip), as reported by the ESWG. Additional details on the plants that tripped are given below, and summarized in Table 8.2 on page 120.

Fermi 2. Fermi 2 is located 25 miles (40 km) northeast of Toledo, Ohio, in southern Michigan on Lake Erie. It was generating about 1,130 megawatts-electric (MWe) before the event. The reactor tripped due to a turbine trip. The turbine trip was likely the result of multiple generator field protection trips (overexcitation and loss of field) as the Fermi 2 generator responded to a series of rapidly changing transients prior to its loss. This is consistent with data that shows large swings of the Fermi 2 generator MVAr prior to its trip.

Offsite power was subsequently lost to the plant auxiliary buses. The safety buses were deenergized and automatically reenergized from the emergency diesel generators. The operators tripped one emergency diesel generator that was paralleled to the grid for testing, after which it automatically loaded. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:22 EDT due to the loss of offsite power. Offsite power was restored to at least one safety bus at about 01:53 EDT on August 15. The following equipment problems were noted: the Combustion Turbine Generator (the alternate AC power source) failed to start from the control room; however, it was successfully started locally. In addition, the Spent Fuel Pool Cooling System was interrupted for approximately 26 hours and reached a maximum temperature of 130 degrees Fahrenheit (55 degrees Celsius). The main generator was reconnected to the grid at about 01:41 EDT on August 20.

FitzPatrick. FitzPatrick is located about 8 miles (13 km) northeast of Oswego, NY, in northern New York on Lake Ontario. It was generating about 850 MWe before the event. The reactor tripped due to low pressure in the hydraulic system that controls the turbine control valves. Low pressure in this system typically indicates a large load reject, for which a reactor trip is expected. In this case the pressure in the system was low because the control system was rapidly manipulating the turbine control valves to control turbine speed, which was being affected by grid frequency fluctuations.

Immediately preceding the trip, both significant over-voltage and under-voltage grid conditions were experienced. Offsite power was subsequently lost to the plant auxiliary buses. The safety buses were deenergized and automatically reenergized from the emergency diesel generators.

The lowest emergency declaration, an Unusual Event, was declared at about 16:26 EDT due to the loss of offsite power. Decay heat removal systems maintained the cooling function for the reactor fuel. Offsite power was restored to at least one safety bus at about 23:07 EDT on August 14. The main generator was reconnected to the grid at about 06:10 EDT on August 18.

Table 8.1. U.S. Nuclear Plant Trip Times

Nuclear Plant	Reactor Trip[a]	Generator Trip[b]
Perry	16:10:25 EDT	16:10:42 EDT
Fermi 2	16:10:53 EDT	16:10:53 EDT
Oyster Creek . . .	16:10:58 EDT	16:10:57 EDT
Nine Mile 1	16:11 EDT	16:11:04 EDT
Indian Point 2 . .	16:11 EDT	16:11:09 EDT
Indian Point 3 . .	16:11 EDT	16:11:23 EDT
FitzPatrick	16:11:04 EDT	16:11:32 EDT
Ginna.	16:11:36 EDT	16:12:17 EDT
Nine Mile 2	16:11:48 EDT	16:11:52 EDT

[a]As determined from licensee data (which may not be synchronized to the national time standard).

[b]As reported by the Electrical System Working Group (synchronized to the national time standard).

Ginna. Ginna is located 20 miles (32 km) northeast of Rochester, NY, in northern New York on Lake Ontario. It was generating about 487 MWe before the event. The reactor tripped due to Over-Temperature-Delta-Temperature. This trip signal protects the reactor core from exceeding temperature limits. The turbine control valves closed down in response to the changing grid conditions. This caused a temperature and pressure transient in the reactor, resulting in an Over-Temperature-Delta-Temperature trip.

Offsite power was not lost to the plant auxiliary buses. In the operators' judgement, offsite power was not stable, so they conservatively energized the safety buses from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel. Offsite power was not lost, and stabilized about 50 minutes after the reactor trip.

The lowest emergency declaration, an Unusual Event, was declared at about 16:46 EDT due to the degraded offsite power. Offsite power was restored to at least one safety bus at about 21:08 EDT on August 14. The following equipment problems were noted: the digital feedwater control system behaved in an unexpected manner following the trip, resulting in high steam generator levels; there was a loss of RCP seal flow indication, which complicated restarting the pumps; and at least one of the power-operated relief valves experienced minor leakage following proper operation and closure during the transient. Also, one of the motor-driven auxiliary feedwater pumps was damaged after running with low flow conditions due to an improper valve alignment. The redundant pumps supplied the required water flow.

The NRC issued a Notice of Enforcement Discretion to allow Ginna to perform mode changes and restart the reactor with one auxiliary feedwater (AFW) pump inoperable. Ginna has two AFW pumps, one turbine-driven AFW pump, and two standby AFW pumps, all powered from safety-related buses. The main generator was reconnected to the grid at about 20:38 EDT on August 17.

Indian Point 2. Indian Point 2 is located 24 miles (39 km) north of New York City on the Hudson River. It was generating about 990 MWe before the event. The reactor tripped due to loss of a reactor coolant pump that tripped because the auxiliary bus frequency fluctuations actuated the under-frequency relay, which protects against inadequate coolant flow through the reactor core. This reactor protection signal tripped the reactor, which resulted in turbine and generator trips.

The auxiliary bus experienced the under-frequency due to fluctuating grid conditions. Offsite power was lost to all the plant auxiliary buses. The safety buses were reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:25 EDT due to the loss of offsite power for more than 15 minutes. Offsite power was restored to at least one safety bus at about 20:02 EDT on August 14. The following equipment problems were noted: the service water to one of the emergency diesel generators developed a leak; a steam generator atmospheric dump valve did not control steam generator pressure in automatic and had to be shifted to manual; a steam trap associated with the turbine-driven AFW pump failed open, resulting in operators securing the turbine after 2.5 hours; loss of instrument air required operators to take manual control of charging and a letdown isolation occurred; and operators in the field could not use radios; and the diesel generator for the Unit 2 Technical Support Center failed to function. Also, several uninterruptible power supplies in the Emergency Operations Facility failed. This reduced the capability for communications and data collection. Alternate equipment was used to maintain vital communications.[1] The main generator was reconnected to the grid at about 12:58 EDT on August 17.

Indian Point 3. Indian Point 3 is located 24 miles (39 km) north of New York City on the Hudson River. It was generating about 1,010 MWe before the event. The reactor tripped due to loss of a reactor coolant pump that tripped because the auxiliary bus frequency fluctuations actuated the under-frequency relay, which protects against inadequate coolant flow through the reactor core. This reactor protection signal tripped the reactor, which resulted in turbine and generator trips.

The auxiliary bus experienced the under-frequency due to fluctuating grid conditions. Offsite power was lost to all the plant auxiliary buses. The safety buses were reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:23 EDT due to the loss of offsite power for more than 15 minutes. Offsite power was restored to at least one safety bus at about 20:12 EDT on August 14. The following equipment problems were noted: a steam generator safety valve lifted below its desired setpoint and was gagged; loss of instrument air, including failure of the diesel backup compressor to start and failure of the backup nitrogen system, resulted in manual control of atmospheric dump valves and AFW pumps needing to be secured to prevent overfeeding the steam generators; a blown fuse in a battery charger resulted in a longer battery discharge; a control rod drive mechanism cable splice failed, and there were high resistance readings on 345-kV breaker-1. These equipment problems required correction prior to startup, which delayed the startup. The diesel generator for the Unit 3 Technical Support Center failed to function. Also, several uninterruptible power supplies in the Emergency Operations Facility failed. This reduced the capability for communications and data collection. Alternate equipment was used to maintain vital communications.[2] The main generator was reconnected to the grid at about 05:03 EDT on August 22.

Nine Mile 1. Nine Mile 1 is located 6 miles (10 km) northeast of Oswego, NY, in northern New York on Lake Ontario. It was generating about 600 MWe before the event. The reactor tripped in response to a turbine trip. The turbine tripped on light load protection (which protects the turbine against a loss of electrical load), when responding to fluctuating grid conditions. The turbine trip caused fast closure of the turbine valves, which, through acceleration relays on the control valves, create a signal to trip the reactor. After a time delay of 10 seconds, the generator tripped on reverse power.

The safety buses were automatically deenergized due to low voltage and automatically reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:33 EDT due to the degraded offsite power. Offsite power was restored to at least one safety bus at about 23:39 EDT on August 14. The following additional equipment problems were noted: a feedwater block valve failed “as is” on the loss of voltage, resulting in a high reactor vessel level; fuses blew in fire circuits, causing control room ventilation isolation and fire panel alarms; and operators were delayed in placing shutdown cooling in service for several hours due to lack of procedure guidance to address particular plant conditions encountered during the shutdown. The main generator was reconnected to the grid at about 02:08 EDT on August 18.

Nine Mile 2. Nine Mile 2 is located 6 miles (10 km) northeast of Oswego, NY, in northern New York on Lake Ontario. It was generating about 1,193 MWe before the event. The reactor scrammed due to the actuation of pressure switches which detected low pressure in the hydraulic system that controls the turbine control valves. Low pressure in this system typically indicates a large load reject, for which a reactor trip is expected. In this case the pressure in the system was low because the control system was rapidly manipulating the turbine control valves to control turbine speed, which was being affected by grid frequency fluctuations.

After the reactor tripped, several reactor level control valves did not reposition, and with the main feedwater system continuing to operate, a high water level in the reactor caused a turbine trip, which caused a generator trip. Offsite power was degraded but available to the plant auxiliary buses. The offsite power dropped below the normal voltage levels, which resulted in the safety buses being automatically energized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 17:00 EDT due to the loss of offsite power to the safety buses for more than 15 minutes. Offsite power was restored to at least one safety bus at about 01:33 EDT on August 15. The following additional equipment problem was noted: a tap changer on one of the offsite power transformers failed, complicating the restoration of one division of offsite power. The main generator was reconnected to the grid at about 19:34 EDT on August 17.

Oyster Creek. Oyster Creek is located 9 miles (14 km) south of Toms River, NJ, near the Atlantic Ocean. It was generating about 629 MWe before the event. The reactor tripped due to a turbine trip. The turbine trip was the result of a generator trip due to actuation of a high Volts/Hz protective trip. The Volts/Hz trip is a generator/transformer protective feature. The plant safety and auxiliary buses transferred from the main generator supply to the offsite power supply following the plant trip. Other than the plant transient, no equipment or performance problems were determined to be directly related to the grid problems.

Post-trip the operators did not get the mode switch to shutdown before main steam header pressure reached its isolation setpoint. The resulting MSIV closure complicated the operator's response because the normal steam path to the main condenser was lost. The operators used the isolation condensers for decay heat removal. The plant safety and auxiliary buses remained energized from offsite power for the duration of the event, and the emergency diesel generators were not started. Decay heat removal systems maintained the cooling function for the reactor fuel. The main generator was reconnected to the grid at about 05:02 EDT on August 17.

Perry. Perry is located 7 miles (11 km) northeast of Painesville, OH, in northern Ohio on Lake Erie. It was generating about 1,275 MWe before the event. The reactor tripped due to a turbine control valve fast closure trip signal. The turbine control valve fast closure trip signal was due to a generator under-frequency trip signal that tripped the generator and the turbine and was triggered by grid frequency fluctuations. Plant operators noted voltage fluctuations and spikes on the main transformer, and the Generator Out-of-Step Supervisory relay actuated approximately 30 minutes before the trip. This supervisory relay senses a ground fault on the grid. The purpose is to prevent a remote fault on the grid from causing a generator out-of-step relay to activate, which would result in a generator trip. Approximately 30 seconds prior to the trip operators noted a number of spikes on the generator field volt meter, which subsequently went offscale high. The MVAr and MW meters likewise went offscale high.

The safety buses were deenergized and automatically reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel. The following equipment problems were noted: a steam bypass valve opened; a reactor water clean-up system pump tripped; the off-gas system isolated, and a keep-fill pump was found to be air-bound, requiring venting and filling before the residual heat removal system loop A and the low pressure core spray system could be restored to service.

The lowest emergency declaration, an Unusual Event, was declared at about 16:20 EDT due to the loss of offsite power. Offsite power was restored to at least one safety bus at about 18:13 EDT on August 14. The main generator was reconnected to the grid at about 23:15 EDT on August 21. After the plant restarted, a surveillance test indicated a problem with one emergency diesel generator.[3]

Nuclear Power Plants With a Significant Transient

The electrical disturbance on August 14 had a significant impact on seven plants that continued to remain connected to the grid. For this review, significant impact means that these plants had significant load adjustments that resulted in bypassing steam from the turbine generator, opening of relief valves, or requiring the onsite emergency diesel generators to automatically start due to low voltage.

Nuclear Power Plants With a Non-Significant Transient

Sixty-four nuclear power plants experienced non-significant transients caused by minor disturbances on the electrical grid. These plants were able to respond to the disturbances through normal control systems. Examples of these transients included changes in load of a few megawatts or changes in frequency of a few-tenths Hz.

Nuclear Power Plants With No Transient

Twenty-four nuclear power plants experienced no transient and saw essentially no disturbances on the grid, or were shut down at the time of the transient.

General Observations Based on the Facts Found During Phase One

The NWG found no evidence that the shutdown of U.S. nuclear power plants triggered the outage or inappropriately contributed to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions). This review did not identify any activity or equipment issues that appeared to start the transient on August 14, 2003. All nine plants that experienced a reactor trip were responding to grid conditions. The severity of the transient caused generators, turbines, or reactor systems to reach a protective feature limit and actuate a plant shutdown.

All nine plants tripped in response to those conditions in a manner consistent with the plant designs. All nine plants safely shut down. All safety functions were effectively accomplished, with few problems, and the plants were maintained in a safe shutdown condition until their restart. Fermi 2, Nine Mile 1, Oyster Creek, and Perry tripped on turbine and generator protective features. FitzPatrick, Ginna, Indian Point 2 and 3, and Nine Mile 2 tripped on reactor protective features.

Nine plants used their emergency diesel generators to power their safety-related buses during the power outage. Offsite power was restored to the safety buses after the grid was energized and the plant operators, in consultation with the transmission system operators, decided the grid was stable. Although the Oyster Creek plant tripped, offsite power was never lost to their safety buses and the emergency diesel generators did not start and were not required. Another plant, Davis-Besse, was already shut down but lost power to the safety buses. The emergency diesel generators started and provided power to the safety buses as designed.

For the eight remaining tripped plants and Davis-Besse (which was already shut down prior to the events of August 14), offsite power was restored to at least one safety bus after a period of time ranging from about 2 hours to about 14 hours, with an average time of about 7 hours. Although Ginna did not lose offsite power, the operators judged offsite power to be unstable and realigned the safety buses to the emergency diesel generators.

The licensees' return to power operation follows a deliberate process controlled by plant procedures and NRC regulations. Ginna, Indian Point 2, Nine Mile 2, and Oyster Creek resumed electrical generation on August 17. FitzPatrick and Nine Mile 1 resumed electrical generation on August 18. Fermi 2 resumed electrical generation on August 20. Perry resumed electrical generation on August 21. Indian Point 3 resumed electrical generation on August 22. Indian Point 3 had equipment issues (failed splices in the control rod drive mechanism power system) that required repair prior to restart. Ginna submitted a special request for enforcement discretion from the NRC to permit mode changes and restart with an inoperable auxiliary feedwater pump. The NRC granted the request for enforcement discretion.

Conclusions of the U.S. Nuclear Working Group

As discussed above, the investigation of the U.S. nuclear power plant responses during the blackout found no significant deficiencies. Accordingly, there are no recommendations here concerning U.S. nuclear power plants. Some areas for consideration on a grid-wide basis were discussed and forwarded to the Electric System Working Group for their review.

On August 14, 2003, nine U.S. nuclear power plants tripped as a result of the loss of offsite power. Nuclear power plants are designed to cope with the loss of offsite power (LOOP) through the use of emergency power supplies (primarily on-site diesel generators). The safety function of most concern during a LOOP is the removal of heat from the reactor core. Although the control rods have been inserted to stop the fission process, the continuing decay of radioactive isotopes in the reactor core produces a significant amount of heat for many weeks. If this decay heat is not removed, it will cause fuel damage and the release of highly radioactive isotopes from the reactor core. The failure of the alternating current emergency power supplies in conjunction with a LOOP is known as a station blackout. Failures of the emergency

Table 8.2. Summary of Events for U. S. Nuclear Power Plants

Nuclear Plant	Unit	Operating Status at Time of Event		Response to Event	
		Full Power	Not Operating	Reactor and Turbine Trip	Emergency Diesels used
Davis-Besse (near Toledo, OH)	1		√		√
Fermi (near Toledo, OH).	2	√		√	√
James A. FitzPatrick (near Oswego, NY) . .	1	√		√	√
Ginna (near Rochester, NY)	1	√		√	√
Indian Point (near New York City, NY)	2	√		√	√
	3	√		√	√
Nine Mile Point (near Oswego, NY)	1	√		√	√
	2	√		√	√
Oyster Creek (near Toms River, NJ)	1	√		√	
Perry (near Painesville, OH)	1	√		√	√

power supplies would seriously hinder the ability of the plant operators to carry out the required safety functions. Nuclear plants can cope with a station blackout for a limited time without suffering fuel damage. However, recovery of the grid or the restoration of an emergency power supply is needed for long-term decay heat removal. For this reason, the NRC considers LOOP events to be potential precursors to more serious situations. The risk of reactor core damage increases as the LOOP frequency or duration increases.

Offsite power is considered the preferred power source for responding to all off-normal events or accidents. However, if the grid is operated in a stressed configuration, the loss of the nuclear plant generation may result in grid voltage dropping below the level needed for the plant safety loads. In that case, each plant is designed such that voltage relays will automatically disconnect the plant safety-related electrical buses from the grid and reenergize them from the emergency diesel generators (EDGs). Although the resultant safety system responses have been analyzed and found acceptable, the loss of offsite power reduces the plant's safety margin. It also increases the risk associated with failures of the EDGs. For these reasons, the NRC periodically assesses the impact of grid reliability on overall nuclear plant safety.

The NRC monitors grid reliability under its normal monitoring programs, such as the operating experience program, and has previously issued reports related to grid reliability. The NRC is continuing with an internal review of the reliability of the electrical grid and the effect on the risk profile for nuclear power plants. The NRC will consider the implications of the August 14, 2003, Northeast blackout under the NRC's regulations. The NRC is conducting an internal review of its station blackout rule, and the results of the August 14th event will be factored into that review. If there are additional findings, the NRC will address them through the NRC's normal process.

Findings of the Canadian Nuclear Working Group

Summary

On the afternoon of August 14, 2003, southern Ontario, along with the northeastern United States, experienced a widespread electrical power system outage. Eleven nuclear power plants in Ontario operating at high power levels at the time of the event either automatically shut down as a result of the grid disturbance or automatically reduced power while waiting for the grid to be reestablished. In addition, the Point Lepreau Nuclear Generating Station in New Brunswick was forced to reduce electricity production for a short period.

The Canadian NWG (CNWG) was mandated to: review the sequence of events for each Canadian nuclear plant; determine whether any events caused or contributed to the power system outage; evaluate any potential safety issues arising as a result of the event; evaluate the effect on safety and the reliability of the grid of design features, operating procedures, and regulatory requirements at Canadian nuclear power plants; and assess the impact of associated regulator performance and regulatory decisions.

In Ontario, 11 nuclear units were operating and delivering power to the grid at the time of the grid disturbance: 4 at Bruce B, 4 at Darlington, and 3 at Pickering B. Of the 11 reactors, 7 shut down as a result of the event (1 at Bruce B, 3 at Darlington, and 3 at Pickering B). Four reactors (3 at Bruce B and 1 at Darlington) disconnected safely from the grid but were able to avoid shutting down and were available to supply power to the Ontario grid as soon as reconnection was enabled by Ontario's Independent Market Operator (IMO).

New Brunswick Power's Point Lepreau Generating Station responded to the loss of grid event by cutting power to 460 MW, returning to fully stable conditions at 16:35 EDT, within 25 minutes of the event. Hydro Québec's (HQ) grid was not affected by the power system outage, and HQ's Gentilly-2 nuclear station continued to operate normally.

Having reviewed the operating data for each plant and the responses of the power stations and their staff to the event, the CNWG concludes the following:

- None of the reactor operators had any advanced warning of impending collapse of the grid.
  - Trend data obtained indicate stable conditions until a few minutes before the event.
  - There were no prior warnings from Ontario's IMO.
- Canadian nuclear power plants did not trigger the power system outage or contribute to its spread. Rather they responded, as anticipated, in order to protect equipment and systems from

the grid disturbances. Plant data confirm the following.

- At Bruce B and Pickering B, frequency and/or voltage fluctuations on the grid resulted in the automatic disconnection of generators from the grid. For those units that were successful in maintaining the unit generators operational, reactor power was automatically reduced.
- At Darlington, load swing on the grid led to the automatic reduction in power of the four reactors. The generators were, in turn, automatically disconnected from the grid.
- Three reactors at Bruce B and one at Darlington were returned to 60% power. These reactors were available to deliver power to the grid on the instructions of the IMO.
- Three units at Darlington were placed in a zero-power hot state, and four units at Pickering B and one unit at Bruce B were placed in a guaranteed shutdown state.

◆ There were no risks to health and safety of workers or the public as a result of the shutdown of the reactors.

- Turbine, generator, and reactor automatic safety systems worked as designed to respond to the loss of grid.
- Station operating staff and management followed approved Operating Policies & Principles (OP&Ps) in responding to the loss of grid. At all times, operators and shift supervisors made appropriately conservative decisions in favor of protecting health and safety.

The CNWG commends the staff of Ontario Power Generation and Bruce Power for their response to the power system outage. At all times, staff acted in accordance with established OP&Ps, and took an appropriately conservative approach to decisions.

During the course of its review, the CNWG also identified the following secondary issues:

◆ Equipment problems and design limitations at Pickering B resulted in a temporary reduction in the effectiveness of some of the multiple safety barriers, although the equipment failure was within the unavailability targets found in the OP&Ps approved by the CNSC as part of Ontario Power Generation's licence.

◆ Existing OP&Ps place constraints on the use of adjuster rods to respond to events involving rapid reductions in reactor power. While greater flexibility with respect to use of adjuster rods would not have prevented the shutdown, some units, particularly those at Darlington, might have been able to return to service less than 1 hour after the initiating event.

◆ Off-site power was unavailable for varying periods of time, from approximately 3 hours at Bruce B to approximately 9 hours at Pickering A. Despite the high priority assigned by the IMO to restoring power to the nuclear stations, the stations had some difficulty in obtaining timely information about the status of grid recovery and the restoration of Class IV power. This information is important for Ontario Power Generation's and Bruce Power's response strategy.

◆ Required regulatory approvals from CNSC staff were obtained quickly and did not delay the restart of the units; however, CNSC staff was unable to immediately activate the CNSC's Emergency Operation Centre because of loss of power to the CNSC's head office building. CNSC staff, therefore, established communications with licensees and the U.S. NRC from other locations.

Introduction

The primary focus of the CNWG during Phase I was to address nuclear power plant response relevant to the power outage of August 14, 2003. Data were collected from each power plant and analyzed in order to determine: the cause of the power outage; whether any activities at these plants caused or contributed to the power outage; and whether there were any significant safety issues. In order to obtain reliable and comparable information and data from each nuclear power plant, a questionnaire was developed to help pinpoint how each nuclear power plant responded to the August 14 grid transients. Where appropriate, additional information was obtained from the ESWG and SWG.

The operating data from each plant were compared against the plant design specifications to determine whether the plants responded as expected. Based on initial plant responses to the questionnaire, supplemental questions were developed, as required, to further clarify outstanding matters. Supplementary information on the design features of Ontario's nuclear power plants was also provided by Ontario Power Generation and Bruce Power. The CNWG also consulted a number of subject area specialists, including CNSC staff, to validate the responses to the questionnaire and to ensure consistency in their interpretation.

In addition to the stakeholder consultations discussed in the Introduction to this chapter, CNSC staff met with officials from Ontario's Independent Market Operator on January 7, 2004.

Typical Design, Operational, and Protective Features of CANDU Nuclear Power Plants

There are 22 CANDU nuclear power reactors in Canada—20 located in Ontario at 5 multi-unit stations (Pickering A and Pickering B located in Pickering, Darlington located in the Municipality of Clarington, and Bruce A and Bruce B located near Kincardine). There are also single-unit CANDU stations at Bécancour, Québec (Gentilly-2), and Point Lepreau, New Brunswick.

In contrast to the pressurized water reactors used in the United States, which use enriched uranium fuel and a light water coolant-moderator, all housed in a single, large pressure vessel, a CANDU reactor uses fuel fabricated from natural uranium, with heavy water as the coolant and moderator. The fuel and pressurized heavy water coolant are contained in 380 to 480 pressure tubes housed in a calandria containing the heavy water moderator under low pressure. Heat generated by the fuel is removed by heavy water coolant that flows through the pressure tubes and is then circulated to the boilers to produce steam from demineralized water.

While the use of natural uranium fuel offers important benefits from the perspectives of safeguards and operating economics, one drawback is that it restricts the ability of a CANDU reactor to recover from a large power reduction. In particular, the lower reactivity of natural uranium fuel means that CANDU reactors are designed with a small number of control rods (called "adjuster rods") that are only capable of accommodating power reductions to 60%. The consequence of a larger power reduction is that the reactor will "poison out" and cannot be made critical for up to 2 days following a power reduction. By comparison, the use of enriched fuel enables a typical pressurized water reactor to operate with a large number of control rods that can be withdrawn to accommodate power reductions to zero power.

A unique feature of some CANDU plants—namely, Bruce B and Darlington—is a capability to maintain the reactor at 60% full power if the generator becomes disconnected from the grid and to maintain this "readiness" condition if necessary for days. Once reconnected to the grid, the unit can be loaded to 60% full power within several minutes and can achieve full power within 24 hours.

As with other nuclear reactors, CANDU reactors normally operate continuously at full power except when shut down for maintenance and inspections. As such, while they provide a stable source of baseload power generation, they cannot provide significant additional power in response to sudden increases in demand. CANDU power plants are not designed for black-start operation; that is, they are not designed to start up in the absence of power from the grid.

Electrical Distribution Systems

The electrical distribution systems at nuclear power plants are designed to satisfy the high safety and reliability requirements for nuclear systems. This is achieved through flexible bus arrangements, high capacity standby power generation, and ample redundancy in equipment.

Where continuous power is required, power is supplied either from batteries (for continuous DC power, Class I) or via inverters (for continuous AC power, Class II). AC supply for safety-related equipment, which can withstand short interruption (on the order of 5 minutes), is provided by Class III power. Class III power is nominally supplied through Class IV; when Class IV becomes unavailable, standby generators are started automatically, and the safety-related loads are picked up within 5 minutes of the loss of Class IV power.

The Class IV power is an AC supply to reactor equipment and systems that can withstand longer interruptions in power. Class IV power can be supplied either from the generator through a transformer or from the grid by another transformer. Class IV power is not required for reactors to shut down safely.

In addition to the four classes of power described above, there is an additional source of power known as the Emergency Power System (EPS). EPS is a separate power system consisting of its own on-site power generation and AC and DC distribution systems whose normal supply is from the Class III power system. The purpose of the EPS system is to provide power to selected safety-related loads following common mode incidents, such as seismic events.

Protective Features of CANDU Nuclear Power Plants

CANDU reactors typically have two separate, independent and diverse systems to shut down the reactor in the event of an accident or transients in the grid. Shutdown System 1 (SDS1) consists of a large number of cadmium rods that drop into the core to decrease the power level by absorbing neutrons. Shutdown System 2 (SDS2) consists of high-pressure injection of gadolinium nitrate into the low-pressure moderator to decrease the power level by absorbing neutrons. Although Pickering A does not have a fully independent SDS2, it does have a second shutdown mechanism, namely, the fast drain of the moderator out of the calandria; removal of the moderator significantly reduces the rate of nuclear fission, which reduces reactor power. Also, additional trip circuits and shutoff rods have recently been added to Pickering A Unit 4 (Shutdown System Enhancement, or SDS-E). Both SDS1 and SDS2 are capable of reducing reactor power from 100% to about 2% within a few seconds of trip initiation.

Fuel Heat Removal Features of CANDU Nuclear Power Plants

Following the loss of Class IV power and shutdown of the reactor through action of SDS1 and/or SDS2, significant heat will continue to be generated in the reactor fuel from the decay of fission products. The CANDU design philosophy is to provide defense in depth in the heat removal systems.

Immediately following the trip and prior to restoration of Class III power, heat will be removed from the reactor core by natural circulation of coolant through the Heat Transport System main circuit following rundown of the main Heat Transport pumps (first by thermosyphoning and later by intermittent buoyancy induced flow). Heat will be rejected from the secondary side of the steam generators through the atmospheric steam discharge valves. This mode of operation can be sustained for many days with additional feedwater supplied to the steam generators via the Class III powered auxiliary steam generator feed pump(s).

In the event that the auxiliary feedwater system becomes unavailable, there are two alternate EPS powered water supplies to steam generators, namely, the Steam Generator Emergency Coolant System and the Emergency Service Water System. Finally, a separate and independent means of cooling the fuel is by forced circulation by means of the Class III powered shutdown cooling system; heat removal to the shutdown cooling heat exchangers is by means of the Class III powered components of the Service Water System.

CANDU Reactor Response to Loss-of-Grid Event

Response to Loss of Grid

In the event of disconnection from the grid, power to shut down the reactor safely and maintain essential systems will be supplied from batteries and standby generators. The specific response of a reactor to disconnection from the grid will depend on the reactor design and the condition of the unit at the time of the event.

60% Reactor Power: All CANDU reactors are designed to operate at 60% of full power following the loss of off-site power. They can operate at this level as long as demineralized water is available for the boilers. At Darlington and Bruce B, steam can be diverted to the condensers and recirculated to the boilers. At Pickering A and Pickering B, excess steam is vented to the atmosphere, thereby limiting the operating time to the available inventory of demineralized water.

0% Reactor Power, Hot: The successful transition from 100% to 60% power depends on several systems responding properly, and continued operation is not guaranteed. The reactor may shut down automatically through the operation of the process control systems or through the action of either of the shutdown systems.

Should a reactor shutdown occur following a load rejection, both Class IV power supplies (from the generator and the grid) to that unit will become unavailable. The main Heat Transport pumps will trip, leading to a loss of forced circulation of coolant through the core. Decay heat will be continuously removed through natural circulation (thermosyphoning) to the boilers, and steam produced in the boilers will be exhausted to the atmosphere via atmospheric steam discharge valves. The Heat Transport System will be maintained at around 250 to 265 degrees Celsius during thermosyphoning. Standby generators will start automatically and restore Class III power to key safety-related systems. Forced circulation in the Heat Transport System will be restored once either Class III or Class IV power is available.

When shut down, the natural decay of fission products will lead to the temporary buildup of neutron absorbing elements in the fuel. If the reactor is not quickly restarted to reverse this natural process, it will "poison-out." Once poisoned-out, the reactor cannot return to operation until the fission products have further decayed, a process which typically takes up to 2 days.

Overpoisoned Guaranteed Shutdown State: In the event that certain problems are identified when reviewing the state of the reactor after a significant transient, the operating staff will cool down and depressurize the reactor, then place it in an overpoisoned guaranteed shutdown state (GSS) through the dissolution of gadolinium nitrate into the moderator. Maintenance will then be initiated to correct the problem.

Return to Service Following Loss of Grid

The return to service of a unit following any one of the above responses to a loss-of-grid event is discussed below. It is important to note that the descriptions provided relate to operations on a single unit. At multi-unit stations, the return to service of several units cannot always proceed in parallel, due to constraints on labor availability and the need to focus on critical evolutions, such as taking the reactor from a subcritical to a critical state.

60% Reactor Power: In this state, the unit can be resynchronized consistent with system demand, and power can be increased gradually to full power over approximately 24 hours.

0% Reactor Power, Hot: In this state, after approximately 2 days for the poison-out, the turbine can be run up and the unit synchronized. Thereafter, power can be increased to high power over the next day. This restart timeline does not include the time required for any repairs or maintenance that might have been necessary during the outage.

Overpoisoned Guaranteed Shutdown State: Placing the reactor in a GSS after it has been shut down requires approximately 2 days. Once the condition that required entry to the GSS is rectified, the restart requires removal of the guarantee, removal of the gadolinium nitrate through ion exchange process, heatup of the Heat Transport System, and finally synchronization to the grid. Approximately 4 days are required to complete these restart activities. In total, 6 days from shutdown are required to return a unit to service from the GSS, and this excludes any repairs that might have been required while in the GSS.

Summary of Canadian Nuclear Power Plant Response to and Safety During the August 14 Outage

On the afternoon of August 14, 2003, 15 Canadian nuclear units were operating: 13 in Ontario, 1 in Québec, and 1 in New Brunswick. Of the 13 Ontario reactors that were critical at the time of the event, 11 were operating at or near full power and 2 at low power (Pickering B Unit 7 and Pickering A Unit 4). All 13 of the Ontario reactors disconnected from the grid as a result of the grid disturbance. Seven of the 11 reactors operating at high power shut down, while the remaining 4 operated in a planned manner that enabled them to remain available to reconnect to the grid at the request of Ontario's IMO. Of the 2 Ontario reactors operating at low power, Pickering A Unit 4 tripped automatically, and Pickering B Unit 7 was tripped manually and shut down. In addition, a transient was experienced at New Brunswick Power's Point Lepreau Nuclear Generating Station, resulting in a reduction in power. Hydro Québec's Gentilly-2 nuclear station continued to operate normally as the Hydro Québec grid was not affected by the grid disturbance.

Nuclear Power Plants With Significant Transients

Pickering Nuclear Generating Station. The Pickering Nuclear Generating Station (PNGS) is located in Pickering, Ontario, on the shores of Lake Ontario, 19 miles (30 km) east of Toronto. It houses 8 nuclear reactors, each capable of delivering 515 MW to the grid. Three of the 4 units at Pickering A (Units 1 through 3) have been shut down since late 1997. Unit 4 was restarted earlier this year following a major refurbishment and was in the process of being commissioned at the time of the event. At Pickering B, 3 units were operating at or near 100% prior to the event, and Unit 7 was being started up following a planned maintenance outage.

Pickering A. As part of the commissioning process, Unit 4 at Pickering A was operating at 12% power in preparation for synchronization to the grid. The reactor automatically tripped on SDS1 due to Heat Transport Low Coolant Flow, when the Heat Transport main circulating pumps ran down following the Class IV power loss. The decision was then made to return Unit 4 to the guaranteed shutdown state. Unit 4 was synchronized to the grid on August 20, 2003. Units 1, 2 and 3 were in lay-up mode.

Pickering B. The Unit 5 Generator Excitation System transferred to manual control due to large voltage oscillations on the grid at 16:10 EDT and then tripped on Loss of Excitation about 1 second later (prior to grid frequency collapse). In response to the generator trip, Class IV buses transferred to the system transformer and the reactor setback. The grid frequency collapse caused the System Service Transformer to disconnect from the grid, resulting in a total loss of Class IV power. The reactor consequently tripped on the SDS1 Low Gross Flow parameter followed by an SDS2 trip due to Low Core Differential Pressure.

The Unit 6 Generator Excitation System also transferred to manual control at 16:10 EDT due to large voltage oscillations on the grid and the generator remained connected to the grid in manual voltage control. Approximately 65 seconds into the event, the grid under-frequency caused all the Class IV buses to transfer to the Generator Service Transformer. Ten seconds later, the generator separated from the Grid. Five seconds later, the generator tripped on Loss of Excitation, which caused a total loss of Class IV power. The reactor consequently tripped on the SDS1 Low Gross Flow parameter, followed by an SDS2 trip due to Low Core Differential Pressure.

Unit 7 was coming back from a planned maintenance outage and was at 0.9% power at the time of the event. The unit was manually tripped after loss of Class IV power, in accordance with procedures and returned to guaranteed shutdown state.

Unit 8 reactor automatically set back on load rejection. The setback would normally have been terminated at 20% power but continued to 2% power because of the low boiler levels. The unit subsequently tripped on the SDS1 Low Boiler Feedline Pressure parameter due to a power mismatch between the reactor and the turbine.

The following equipment problems were noted. At Pickering, the High Pressure Emergency Coolant Injection System (HPECIS) pumps are designed to operate from a Class IV power supply. As a result of the shutdown of all the operating units, the HPECIS at both Pickering A and Pickering B became unavailable for 5.5 hours. (The design of Pickering A and Pickering B HPECIS must be such that the fraction of time for which it is not available can be demonstrated to be less than 10^{-3} years—about 8 hours per year. This was the first unavailability of the HPECIS for 2003.) In addition, Emergency High Pressure Service Water System restoration for all Pickering B units was delayed because of low suction pressure supplying the Emergency High Pressure Service Water pumps. Manual operator intervention was required to restore some pumps back to service.

Units were synchronized to the grid as follows: Unit 8 on August 22, Unit 5 on August 23, Unit 6 on August 25, and Unit 7 on August 29.

Darlington Nuclear Generating Station. Four reactors are located at the Darlington Nuclear Generation Station, which is on the shores of Lake Ontario in the Municipality of Clarington, 43 miles (70 km) east of Toronto. All four of the reactors are licensed to operate at 100% of full power, and each is capable of delivering approximately 880 MW to the grid.

Unit 1 automatically stepped back to the 60% reactor power state upon load rejection at 16:12 EDT. Approval by the shift supervisor to automatically withdraw the adjuster rods could not be provided due to the brief period of time for the shift supervisor to complete the verification of systems as per procedure. The decreasing steam pressure and turbine frequency then required the reactor to be manually tripped on SDS1, as per procedure for loss of Class IV power. The trip occurred at 16:24 EDT, followed by a manual turbine trip due to under-frequency concerns.

Like Unit 1, Unit 2 automatically stepped back upon load rejection at 16:12 EDT. As with Unit 1, there was insufficient time for the shift supervisor to complete the verification of systems, and faced with decreasing steam pressure and turbine frequency, the decision was made to shut down Unit 2. Due to under-frequency on the main Primary Heat Transport pumps, the turbine was tripped manually which resulted in an SDS1 trip at 16:28 EDT.

Unit 3 experienced a load rejection at 16:12 EDT, and during the stepback Unit 3 was able to sustain operation with steam directed to the condensers. After system verifications were complete, approval to place the adjuster rods on automatic was obtained in time to recover, at 59% reactor power. The unit was available to resynchronize to the grid.

Unit 4 experienced a load rejection at 16:12 EDT, and required a manual SDS1 trip due to the loss of Class II bus. This was followed by a manual turbine trip.

The following equipment problems were noted: Unit 4 Class II inverter trip on BUS A3 and subsequent loss of critical loads prevented unit recovery. The Unit 0 Emergency Power System BUS B135 power was lost until the Class III power was restored. (A planned battery bank B135 change out was in progress at the time of the blackout.)

Units were synchronized to the grid as follows: Unit 3 at 22:00 EDT on August 14; Unit 2 on August 17, 2003; Unit 1 on August 18, 2003; and Unit 4 on August 18, 2003.

Bruce Power. Eight reactors are located at Bruce Power on the eastern shore of Lake Huron between Kincardine and Port Elgin, Ontario. Units 5 through 8 are capable of generating 840 MW each. Presently these reactors are operating at 90% of full power due to license conditions imposed by the CNSC. Units 1 through 4 have been shut down since December 31, 1997. At the time of the event, work was being performed to return Units 3 and 4 to service.

Bruce A. Although these reactors were in guaranteed shutdown state, they were manually tripped, in accordance with operating procedures. SDS1 was manually tripped on Units 3 and 4, as per procedures for a loss of Class IV power event. SDS1 was re-poised on both units when the station power supplies were stabilized. The emergency transfer system functioned as per design, with the Class III standby generators picking up station electrical loads. The recently installed Qualified Diesel Generators received a start signal and were available to pick up emergency loads if necessary.

Bruce B. Units 5, 6, 7, and 8 experienced initial generation rejection and accompanying stepback on all four reactor units. All generators separated from the grid on under-frequency at 16:12 EDT. Units 5, 7, and 8 maintained reactor power at 60% of full power and were immediately available for reconnection to the grid.

Although initially surviving the loss of grid event, Unit 6 experienced an SDS1 trip on insufficient Neutron Over Power (NOP) margin. This occurred while withdrawing Bank 3 of the adjusters in an attempt to offset the xenon transient, resulting in a loss of Class IV power.

The following equipment problems were noted: An adjuster rod on Unit 6 had been identified on August 13, 2003, as not working correctly. Unit 6 experienced a High Pressure Recirculation Water line leak, and the Closed Loop Demineralized Water loop lost inventory to the Emergency Water Supply System.

Units were synchronized to the grid as follows: Unit 8 at 19:14 EDT on August 14, 2003; Unit 5 at 21:04 EDT on August 14; and Unit 7 at 21:14 EDT on August 14, 2003. Unit 6 was resynchronized at 02:03 EDT on August 23, 2003, after maintenance was conducted.

Point Lepreau Nuclear Generating Station. The Point Lepreau nuclear station overlooks the Bay of Fundy on the Lepreau Peninsula, 25 miles (40 km) southwest of Saint John, New Brunswick. Point Lepreau is a single-unit CANDU 6, designed for a gross output of 680 MW. It is owned and operated by New Brunswick Power.

Point Lepreau was operating at 91.5% of full power (610 MWe) at the time of the event. When the event occurred, the unit responded to changes in grid frequency as per design. The net impact was a short-term drop in output by 140 MW, with reactor power remaining constant and excess thermal energy being discharged via the unit steam discharge valves. During the 25 seconds of the event, the unit stabilizer operated numerous times to help dampen the turbine generator speed oscillations that were being introduced by the grid frequency changes. Within 25 minutes of the event initiation, the turbine generator was reloaded to 610 MW. Given the nature of the event that occurred, there were no unexpected observations on the New Brunswick Power grid or at Point Lepreau Generating Station throughout the ensuing transient.

Nuclear Power Plants With No Transient

Gentilly-2 Nuclear Station. Hydro Québec owns and operates Gentilly-2 nuclear station, located on the south shore of the St. Lawrence River opposite the city of Trois-Rivières, Québec. Gentilly-2 is capable of delivering approximately 675 MW to Hydro Québec's grid. The Hydro Québec grid was not affected by the power system outage and Gentilly-2 continued to operate normally.

General Observations Based on the Facts Found During Phase I

Following the review of the data provided by the Canadian nuclear power plants, the CNWG concludes the following:

- None of the reactor operators had any advanced warning of impending collapse of the grid.
- Canadian nuclear power plants did not trigger the power system outage or contribute to its spread.

- There were no risks to the health and safety of workers or the public as a result of the concurrent shutdown of several reactors. Automatic safety systems for the turbine generators and reactors worked as designed. (See Table 8.3 for a summary of shutdown events for Canadian nuclear power plants.)

The CNWG also identified the following secondary issues:

- Equipment problems and design limitations at Pickering B resulted in a temporary reduction in the effectiveness of some of the multiple safety barriers, although the equipment failure was within the unavailability targets found in the OP&Ps approved by the CNSC as part of Ontario Power Generation's license.
- Existing OP&Ps place constraints on the use of adjuster rods to respond to events involving rapid reductions in reactor power. While greater flexibility with respect to use of adjuster rods would not have prevented the shutdown, some units, particularly those at Darlington, might have been able to return to service less than 1 hour after the initiating event.
- Off-site power was unavailable for varying periods of time, from approximately 3 hours at Bruce B to approximately 9 hours at Pickering A. Despite the high priority assigned by the IMO to restoring power to the nuclear stations, the stations had some difficulty obtaining timely information about the status of grid recovery and the restoration of Class IV power. This information is important for Ontario Power Generation's and Bruce Power's response strategy.
- Required regulatory approvals from CNSC staff were obtained quickly and did not delay the

Table 8.3. Summary of Shutdown Events for Canadian Nuclear Power Plants

		Operating Status at Time of Event			Response to Event			
							Reactor Trip	
Generating Station	Unit	Full Power	Startup	Not Operating	Stepback to 60% Power, Available To Supply Grid	Turbine Trip	SDS1	SDS2
Pickering NGS	1			√			(a)	
	2			√				
	3			√				
	4		√				√	(b)
	5	√					√	√
	6	√					√	√
	7		√				√	
	8	√					√	
Darlington NGS	1	√				√	√	
	2	√				√	√	
	3	√			√			
	4	√				√	√	
Bruce Nuclear Power Development	1			√				
	2			√				
	3			√			√	
	4			√			√	
	5	√			√			
	6	√					√	
	7	√			√			
	8	√			√			

[a]Pickering A Unit 1 tripped as a result of electrical bus configuration immediately prior to the event which resulted in a temporary loss of Class II power.

[b]Pickering A Unit 4 also tripped on SDS-E.

Notes: Unit 7 at Pickering B was operating at low power, warming up prior to reconnecting to the grid after a maintenance outage. Unit 4 at Pickering A was producing at low power, as part of the reactor's commissioning after extensive refurbishment since being shut down in 1997.

restart of the units; however, CNSC staff was unable to immediately activate the CNSC's Emergency Operation Centre because of loss of power to the CNSC's head office building. CNSC staff, therefore, established communications with licensees and the U.S. NRC from other locations.

Regulatory Activities Subsequent to the Blackout

The actuation of emergency shutdown systems at Bruce, Darlington and Pickering, and the impairment of the High Pressure Emergency Coolant Injection System (HPECIS) at Pickering are events for which licensees need to file reports with the Canadian Nuclear Safety Commission (CNSC), in accordance with Regulatory Standard S 99, "Reporting Requirements for Operating Nuclear Power Plants." Reports have been submitted by Ontario Power Generation (OPG) and Bruce Power, and are being followed up by staff from the CNSC as part of the CNSC's normal regulatory process. This includes CNSC's review and approval, where appropriate, of any actions taken or proposed to be taken to correct any problems in design, equipment or operating procedures identified by OPG and Bruce Power.

As a result of further information about the event gathered by CNSC staff during followup inspections, the temporary impairment of the HPECIS at Pickering has been rated by CNSC staff as Level 2 on the International Nuclear Event Scale, indicating that there was a significant failure in safety provisions, but with sufficient backup systems, or "defense-in-depth," in place to cope with potential malfunctions. Since August 2003, OPG has implemented procedural and operational changes to improve the performance of the safety systems at Pickering.

Conclusions of the Canadian Nuclear Working Group

As discussed above, Canadian nuclear power plants did not trigger the power system outage or contribute to its spread. The CNWG therefore made no recommendations with respect to the design or operation of Canadian nuclear plants to improve the reliability of the Ontario electricity grid.

The CNWG made two recommendations, one concerning backup electrical generation equipment to the CNSC's Emergency Operations Centre and another concerning the use of adjuster rods during future events involving the loss of off-site power. These are presented in Chapter 10 along with the Task Force's recommendations on other subjects.

Despite some comments to the contrary, the CNWG's investigation found that the time to restart the reactors was reasonable and in line with design specifications for the reactors. Therefore, the CNWG made no recommendations for action on this matter. Comments were also made regarding the adequacy of generation capacity in Ontario and the appropriate mix of technologies for electricity generation. This is a matter beyond the CNWG's mandate, and it made no recommendations on this issue.

Perspective of Nuclear Regulatory Agencies on Potential Changes to the Grid

The NRC and the CNSC, under their respective regulatory authorities, are entrusted with providing reasonable assurance of adequate protection of public health and safety. As the design and operation of the electricity grid is taken into account when evaluating the safety analysis of nuclear power plants, changes to the electricity grid must be evaluated for the impact on plant safety. As the Task Force final recommendations result in actions to affect changes, the NRC and the CNSC will assist by evaluating potential effects on the safety of nuclear power plant operation.

The NRC and the CNSC acknowledge that future improvements in grid reliability will involve coordination among many groups. The NRC and the CNSC intend to maintain the good working relationships that have been developed during the Task Force investigation to ensure that we continue to share experience and insights and work together to maintain an effective and reliable electric supply system.

Endnotes

1 Further details are available in the NRC Special Inspection Report dated December 22, 2003, ADAMS Accession No. ML033570386.

2 Further details are available in the NRC Special Inspection Report dated December 22, 2003, ADAMS Accession No. ML033570386.

3 Further details are available in the NRC Special Inspection Report dated October 10, 2003, ADAMS Acccession No. ML032880107.

9. Physical and Cyber Security Aspects of the Blackout

Summary and Primary Findings

After the Task Force Interim Report was issued in November 2003, the Security Working Group (SWG) continued in its efforts to investigate whether a malicious cyber event directly caused or significantly contributed to the power outage of August 14, 2003. These efforts included additional analyses of interviews conducted prior to the release of the Interim Report and additional consultations with representatives from the electric power sector. The information gathered from these efforts validated the SWG's Interim Report preliminary findings and the SWG found no reason to amend, alter, or negate any of the information submitted to the Task Force for the Interim Report.

Specifically, further analysis by the SWG found no evidence that malicious actors caused or contributed to the power outage, nor is there evidence that worms or viruses circulating on the Internet at the time of the power outage had an effect on power generation and delivery systems of the companies directly involved in the power outage. The SWG acknowledges reports of al-Qaeda claims of responsibility for the power outage of August 14, 2003. However, these claims are not consistent with the SWG's findings. SWG analysis also brought to light certain concerns respecting the possible failure of alarm software; links to control and data acquisition software; and the lack of a system or process for some grid operators to adequately view the status of electric systems outside of their immediate control.

After the release of the Interim Report in November 2003, the SWG determined that the existing data, and the findings derived from analysis of those data, provided sufficient certainty to exclude the probability that a malicious cyber event directly caused or significantly contributed to the power outage events. As such, further data collection efforts to conduct broader analysis were deemed unnecessary. While no additional data were collected, further analysis and interviews conducted after the release of the Interim Report allowed the SWG to validate its preliminary findings and the SWG to make recommendations on those findings:

- Interviews and analyses conducted by the SWG indicate that within some of the companies interviewed there are potential opportunities for cyber system compromise of Energy Management Systems (EMS) and their supporting information technology (IT) infrastructure. Indications of procedural and technical IT management vulnerabilities were observed in some facilities, such as unnecessary software services not denied by default, loosely controlled system access and perimeter control, poor patch and configuration management, and poor system security documentation. This situation caused the SWG to support the promulgation, implementation, and enforcement of cyber and physical security standards for the electric power sector.

Recommendation 32, page 163

- A failure in a software program not linked to malicious activity may have significantly contributed to the power outage. Since the issuance of the Interim Report, the SWG consulted with the software program's vendor and confirmed that since the August 14, 2003, power outage, the vendor provided industry with the necessary information and mitigation steps to address this software failure. In Canada, a survey was posted on the Canadian Electricity Association (CEA) secure members-only web site to determine if the software was in use. The responses indicated that it is not used by Canadian companies in the industry.

Recommendation 33, page 164

- Internal and external links from Supervisory Control and Data Acquisition (SCADA) networks to other systems introduced vulnerabilities.

Recommendation 34, page 165

- In some cases, Control Area (CA) and Reliability Coordinator (RC) visibility into the operations of surrounding areas was lacking.

Recommendation 35, page 165

The SWG's analysis is reflected in a total of 15 recommendations, two of which were combined with similar concerns by the ESWG (Recommendations 19 and 22); for the remaining 13, see Recommendations 32-44 (pages 163-169).

Overall, the SWG's final report was the result of interviews conducted with representatives of Cinergy, FirstEnergy, American Electric Power (AEP), PJM Interconnect, the Midwest Independent System Operator (MISO), the East Central Area Reliability Coordinating Agreement (ECAR), and GE Power Systems Division. These entities were chosen due to their proximity to the causes of the power outage based on the analysis of the Electric System Working Group (ESWG). The findings contained in this report relate only to those entities surveyed. The final report also incorporates information gathered from third party sources as well as federal security and intelligence communities.

In summary, SWG analysis provided no evidence that a malicious cyber attack was a direct or indirect cause of the August 14, 2003, power outage. This conclusion is supported by the SWG's event timeline, detailed later in this chapter, which explains in detail the series of non-malicious human and cyber failures that ultimately resulted in the power outage. In the course of its analysis the SWG, however, did identify a number of areas of concern respecting cyber security aspects of the electricity sector.

SWG Mandate and Scope

It is widely recognized that the increased reliance on IT by critical infrastructure sectors, including the energy sector, has increased the vulnerability of these systems to disruption via cyber means. The ability to exploit these vulnerabilities has been demonstrated in North America. The SWG was comprised of United States and Canadian federal, state, provincial and local experts in both physical and cyber security and its objective was to determine the role, if any, that a malicious cyber event played in causing, or contributing to, the power outage of August 14, 2003. For the purposes of its work, the SWG defined a "malicious cyber event" as the manipulation of data, software or hardware for the purpose of deliberately disrupting the systems that control and support the generation and delivery of electric power.

The SWG worked closely with the United States and Canadian law enforcement, intelligence and homeland security communities to examine the possible role of malicious actors in the power outage. A primary activity in this endeavor was the collection and review of available intelligence related to the power outage of August 14, 2003. The SWG also collaborated with the energy industry to examine the cyber systems that control power generation and delivery operations, the physical security of cyber assets, cyber policies and procedures and the functionality of supporting infrastructures—such as communication systems and backup power generation, which facilitate the smooth running operation of cyber assets—to determine if the operation of these systems was affected by malicious activity. The SWG coordinated its efforts with those of other Working Groups and there was a significant interdependence on each groups work products and findings. The SWG's focus was on the cyber operations of those companies in the United States involved in the early stages of the power outage timeline, as identified by the ESWG.

Outside of the SWG's scope was the examination of the non-cyber physical infrastructure aspects of the power outage of August 14, 2003. The Interim Report detailed the SWG's availability to investigate breaches of physical security unrelated to the cyber dimensions of the infrastructure on behalf of the Task Force but no incidents came to the SWG's attention during its work. Also outside of the scope of the SWG's work was analysis of the impacts the power outage had on other critical infrastructure sectors. Both Public Safety and Emergency Preparedness Canada and the U.S. Department of Homeland Security (DHS) examined these issues, but not within the context of the SWG.

Cyber Security in the Electricity Sector

The generation and delivery of electricity has been, and continues to be, a target of malicious groups and individuals intent on disrupting this system. Even attacks that do not directly target the electricity sector can have disruptive effects on electricity system operations. Many malicious code attacks, by their very nature, are unbiased and tend to interfere with operations supported by vulnerable applications. One such incident occurred in January 2003, when the "Slammer" Internet worm took down monitoring computers at FirstEnergy Corporation's idled Davis-Besse nuclear plant. A subsequent report by the North American Electric Reliability Council (NERC) concluded that although the infection caused no outages, it blocked commands that operated other power utilities.[1]

This example, among others, highlights the increased vulnerability to disruption via cyber means faced by North America's critical infrastructure sectors, including the energy sector. Of specific concern to the United States and Canadian governments are the SCADA networks, which contain computers and applications that perform a wide variety of functions across many industries. In electric power, SCADA includes telemetry for status and control, as well as EMS, protective relaying and automatic generation control. SCADA systems were developed to maximize functionality and interoperability, with little attention given to cyber security. These systems, many of which were intended to be isolated, now find themselves for a variety of business and operational reasons, either directly or indirectly connected to the global Internet. For example, in some instances, there may be a need for employees to monitor SCADA systems remotely. However, connecting SCADA systems to a remotely accessible computer network can present security risks. These risks include the compromise of sensitive operating information and the threat of unauthorized access to SCADA systems' control mechanisms.

Security has always been a priority for the electricity sector in North America; however, it is a greater priority now than ever before. CAs and RCs recognize that the threat environment is changing and that the risks are greater than in the past, and they have taken steps towards improving their security postures. NERC's Critical Infrastructure Protection Advisory Group has been examining ways to improve both the physical and cyber security dimensions of the North American power grid. This group is comprised of Canadian and U.S. industry experts in the areas of cyber security, physical security and operational security. The creation of a national SCADA program is now also under discussion in the U.S. to improve the physical and cyber security of these control systems. The Canadian Electricity Association's Critical Infrastructure Working Group is examining similar measures.

Information Collection and Analysis

After analyzing information already obtained from stakeholder interviews, telephone transcripts, law enforcement and intelligence information, and other ESWG working documents, the SWG determined that it was not necessary to analyze other sources of data on the cyber operations of those such as log data from routers, intrusion detection systems, firewalls, EMS, change management logs, and physical security materials.

The SWG was divided into six sub-teams to address the discrete components of this investigation: Cyber Analysis, Intelligence Analysis, Physical Analysis, Policies and Procedures, Supporting Infrastructure, and Root Cause Liaison. The SWG organized itself in this manner to create a holistic approach to address each of the main areas of concern with regards to power grid vulnerabilities. Rather than analyze each area of concern separately, the SWG sub-team structure provided a more comprehensive framework in which to investigate whether malicious activity was a cause of the power outage of August 14, 2003. Each sub-team was staffed with Subject Matter Experts (SMEs) from government, industry, and academia to provide the analytical breadth and depth necessary to complete each sub-team's objective. A detailed overview of the sub-team structure and activities for each sub-team is provided below.

1. Cyber Analysis

The Cyber Analysis sub-team was led by the CERT® Coordination Center (CERT/CC) at Carnegie Mellon University and the Royal Canadian Mounted Police (RCMP). This team was focused on analyzing and reviewing electronic media of computer networks in which online communications take place. The sub-team examined these networks to determine if they were maliciously used to cause, or contribute to the August 14, 2003, outage. Specifically, the SWG reviewed materials created on behalf of DHS's National Communication System (NCS). These materials covered the analysis and conclusions of their Internet Protocol (IP) modeling correlation study of Blaster (a malicious Internet worm first noticed on August 11, 2003) and the power outage. This

NCS analysis supports the SWG's finding that viruses and worms prevalent across the Internet at the time of the outage did not have any significant impact on power generation and delivery systems. The team also conducted interviews with vendors to identify known system flaws and vulnerabilities.

This sub-team took a number of steps, including reviewing NERC reliability standards to gain a better understanding of the overall security posture of the electric power industry. Additionally, the sub-team participated in meetings in Baltimore on August 22 and 23, 2003. The meetings provided an opportunity for the cyber experts and the power industry experts to understand the details necessary to conduct an investigation.

Members of the sub-team also participated in the NERC/Department of Energy (DOE) Fact Finding meeting held in Newark, New Jersey on September 8, 2003. Each company involved in the outage provided answers to a set of questions related to the outage. The meeting helped to provide a better understanding of what each company experienced before, during and after the outage. Additionally, sub-team members participated in interviews with grid operators from FirstEnergy on October 8 and 9, 2003, and from Cinergy on October 10, 2003.

2. Intelligence Analysis

The Intelligence Analysis sub-team was led by DHS and the RCMP, which worked closely with Federal, State and local law enforcement, intelligence and homeland security organizations to assess whether the power outage was the result of a malicious attack.

SWG analysis provided no evidence that malicious actors—be they individuals or organizations—were responsible for, or contributed to, the power outage of August 14, 2003. Additionally, the sub-team found no indication of deliberate physical damage to power generating stations and delivery lines on the day of the outage and there were no reports indicating the power outage was caused by a computer network attack.

Both U.S. and Canadian government authorities provide threat intelligence information to their respective energy sectors when appropriate. No intelligence reports prior to, during or after the power outage indicated any specific terrorist plans or operations against the energy infrastructure. There was, however, threat information of a general nature relating to the sector which was provided to the North American energy industry by U.S. and Canadian Government agencies in late July 2003. This information indicated that al-Qaeda might attempt to carry out a physical attack involving explosions at oil production facilities, power plants or nuclear plants on the east coast of the U.S. during the summer of 2003. The type of physical attack described in the intelligence that prompted this threat warning is not consistent with the events causing the power outage as there was no indication of a kinetic event before, during, or immediately after the power outage of August 14, 2003.

Despite all of the above indications that no terrorist activity caused the power outage, al-Qaeda publicly claimed responsibility for its occurrence:

- *August 18, 2003:* Al-Hayat, an Egyptian media outlet, published excerpts from a communiqué attributed to al-Qaeda. Al Hayat claimed to have obtained the communiqué from the website of the International Islamic Media Center. The content of the communiqué asserts that the "brigades of Abu Fahes Al Masri had hit two main power plants supplying the East of the U.S., as well as major industrial cities in the U.S. and Canada, . . . its ally in the war against Islam (New York and Toronto) and their neighbors." Furthermore, the operation "was carried out on the orders of Osama bin Laden to hit the pillars of the U.S. economy," as "a realization of bin Laden's promise to offer the Iraqi people a present." The communiqué does not specify the way the alleged sabotage was carried out, but does elaborate on the alleged damage the sabotage caused to the U.S. economy in the areas of finance, transportation, energy and telecommunications.

Additional claims and commentary regarding the power outage appeared in various Middle Eastern media outlets:

- *August 26, 2003:* A conservative Iranian daily newspaper published a commentary regarding the potential of computer technology as a tool for terrorists against infrastructures dependent on computer networks, most notably water, electric, public transportation, trade organizations and "supranational" companies in the United States.

- *September 4, 2003:* An Islamist participant in a Jihadist chat room forum claimed that sleeper cells associated with al-Qaeda used the power outage as a cover to infiltrate the U.S. from Canada.

However, these claims as known are not consistent with the SWG's findings. They are also not consistent with congressional testimony of the Federal Bureau of Investigation (FBI). Larry A. Mefford, Executive Assistant Director in charge of the FBI's Counterterrorism and Counterintelligence programs, testified in U.S. Congress on September 4, 2003, that:

> *"To date, we have not discovered any evidence indicating that the outage was a result of activity by international or domestic terrorists or other criminal activity."*[2]

Mr. Mefford also testified that:

> *"The FBI has received no specific, credible threats to electronic power grids in the United States in the recent past and the claim of the Abu Hafs al-Masri Brigade to have caused the blackout appears to be no more than wishful thinking. We have no information confirming the actual existence of this group."*[3]

Current assessments suggest that there are terrorists and other malicious actors who have the capability to conduct a malicious cyber attack with potential to disrupt the energy infrastructure. Although such an attack cannot be ruled out entirely, an examination of available information and intelligence does not support any claims of a deliberate attack against the energy infrastructure on, or leading up to, August 14, 2003. The few instances of physical damage that occurred on power delivery lines were the result of natural events and not of sabotage. No intelligence reports prior to, during or after the power outage indicated any specific terrorist plans or operations against the energy infrastructure. No incident reports detail suspicious activity near the power generation plants or delivery lines in question.

3. Physical Analysis

The Physical Analysis sub-team was led by the United States Secret Service and the RCMP. These organizations have a particular expertise in physical security assessments in the energy sector. The sub-team focused on issues related to how the cyber-related facilities of the energy sector companies were secured, including the physical integrity of data centers and control rooms along with security procedures and policies used to limit access to sensitive areas. Focusing on the facilities identified as having a causal relationship to the outage, the sub-team sought to determine if the physical integrity of these cyber facilities was breached, whether externally or by an insider, prior to or during the outage, and if so, whether such a breach caused or contributed to the power outage.

Although the sub-team analyzed information provided to both the ESWG and Nuclear Working Groups, the Physical Analysis sub-team also reviewed information resulting from face-to-face meetings with energy sector personnel and site-visits to energy sector facilities to determine the physical integrity of the cyber infrastructure.

The sub-team compiled a list of questions covering location, accessibility, cameras, alarms, locks, fire protection and water systems as they apply to computer server rooms. Based on discussions of these questions during its interviews, the sub-team found no evidence that the physical integrity of the cyber infrastructure was breached. Additionally, the sub-team examined access and control measures used to allow entry into command and control facilities and the integrity of remote facilities.

The sub-team also concentrated on mechanisms used by the companies to report unusual incidents within server rooms, command and control rooms and remote facilities. The sub-team also addressed the possibility of an insider attack on the cyber infrastructure.

4. Policies and Procedures

The Policies and Procedures sub-team was led by DHS and Public Safety and Emergency Preparedness Canada. Personnel from these organizations have strong backgrounds in the fields of electric delivery operations, automated control systems including SCADA and EMS, and information security.

This sub-team was focused on examining the overall policies and procedures that may or may not have been in place during the events leading up to and during the power outage of August 14, 2003. Policies that the team examined revolved centrally around the cyber systems of the companies identified in the early stages of the power outage. Of specific interest to the team were policies and procedures regarding the upgrade and maintenance (to include system patching) of the command and control (C2) systems, including SCADA and EMS. The Policies and Procedures sub-team was also interested in the procedures for contingency operations and restoration of systems in the event of a computer system failure, or a cyber event such as an active hack or the discovery of malicious code.

5. Supporting Infrastructure

The Supporting Infrastructure sub-team was led by a DHS expert with experience assessing supporting infrastructure elements such as water cooling for computer systems, back-up power systems, heating, ventilation and air conditioning (HVAC), and supporting telecommunications networks. Public Safety and Emergency Preparedness Canada was the Canadian co-lead for this effort. This team analyzed the integrity of the supporting infrastructure and its role, if any, in the power outage on August 14, 2003. It sought to determine whether the supporting infrastructure was performing at a satisfactory level leading up to and during the power outage of August 14, 2003. In addition, the team verified with vendors if there were maintenance issues that may have impacted operations prior to and during the outage.

The sub-team specifically focused on the following key issues in visits to each of the designated electrical entities:

1. Carrier/provider/vendor for the supporting infrastructure services and/or systems at select company facilities;
2. Loss of service before and/or after the power outage;
3. Conduct of maintenance activities before and/or after the power outage;
4. Conduct of installation activities before and/or after the power outage;
5. Conduct of testing activities before and/or after the power outage;
6. Conduct of exercises before and/or after the power outage; and
7. Existence of a monitoring process (log, checklist etc.) to document the status of supporting infrastructure services.

6. Root Cause Analysis

The SWG Root Cause Liaison Sub-Team (SWG/RC) followed the work of the ESWG to identify potential root causes of the power outage. As these root cause elements were identified, the sub-team assessed with the ESWG any potential linkages to physical and/or cyber malfeasance. The final analysis of the SWG/RC team found no causal link between the power outage and malicious activity, whether physical or cyber initiated.

Cyber Timeline

The following sequence of events was derived from discussions with representatives of FirstEnergy and the Midwest Independent System Operator (MISO). All times are approximate.

The first significant cyber-related event of August 14, 2003, occurred at 12:40 EDT at the MISO. At this time, a MISO EMS engineer purposely disabled the automatic periodic trigger on the State Estimator (SE) application, an application that allows MISO to determine the real-time state of the power system for its region. The disablement of the automatic periodic trigger, a program feature that causes the SE to run automatically every five minutes, is a necessary operating procedure when resolving a mismatched solution produced by the SE. The EMS engineer determined that the mismatch in the SE solution was due to the SE model depicting Cinergy's Bloomington-Denois Creek 230-kV line as being in service, when it had actually been out of service since 12:12 EDT.

At 13:00 EDT, after making the appropriate changes to the SE model and manually triggering the SE, the MISO EMS engineer achieved two valid solutions.

At 13:30 EDT, the MISO EMS engineer went to lunch. However, he forgot to re-engage the automatic periodic trigger.

At 14:14 EDT, FirstEnergy's "Alarm and Event Processing Routine," (AEPR) a key software program that gives grid operators visual and audible indications of events occurring on their portion of the grid, began to malfunction. FirstEnergy grid operators were unaware that the software was not functioning properly. This software did not become functional again until much later that evening.

At 14:40 EDT, an Ops Engineer discovered the SE was not solving and went to notify an EMS engineer that the SE was not solving.

At 14:41 EDT, FirstEnergy's server running the AEPR software failed to the backup server. Control room staff remained unaware that the AEPR software was not functioning properly.

At 14:44 EDT, a MISO EMS engineer, after being alerted by the Ops Engineer, re-activated the automatic periodic trigger and, for speed, manually triggered the program. However, the SE program again showed a mismatch.

At 14:54 EDT, FirstEnergy's backup server failed. AEPR continued to malfunction. The Area Control Error Calculations (ACE) and Strip Charting routines malfunctioned and the dispatcher user interface slowed significantly.

At 15:00 EDT, FirstEnergy used its emergency backup system to control the system and make ACE calculations. ACE calculations and control systems continued to run on the emergency backup system until roughly 15:08 EDT, when the primary server was restored.

At 15:05 EDT, FirstEnergy's Harding-Chamberlin 345-kV line tripped and locked out. FirstEnergy grid operators did not receive notification from the AEPR software which continued to malfunction, unbeknownst to the FirstEnergy grid operators.

At 15:08 EDT, using data obtained at roughly 15:04 EDT (it takes roughly five minutes for the SE to provide a result), the MISO EMS engineer concluded that the SE mismatched due to a line outage. His experience allowed him to isolate the outage to the Stuart-Atlanta 345-kV line (which tripped about an hour earlier at 14:02 EDT). He took the Stuart-Atlanta line out of service in the SE model and got a valid solution.

Also at 15:08 EDT, the FirstEnergy primary server was restored. ACE calculations and control systems were now running on the primary server. AEPR continued to malfunction, unbeknownst to the FirstEnergy grid operators.

At 15:09 EDT, the MISO EMS engineer went to the control room to tell the grid operators that he thought the Stuart-Atlanta line was out of service. Grid operators referred to their "Outage Scheduler" and informed the EMS Engineer that their data showed the Stuart-Atlanta line was "up" and that the EMS engineer should depict the line as in service in the SE model. At 15:17 EDT, the EMS engineer ran the SE with the Stuart-Atlanta line "live," but the model again mismatched.

At 15:29 EDT, the MISO EMS Engineer asked MISO grid operators to call PJM Interconnect, LLC to determine the status of the Stuart-Atlanta line. MISO was informed that the Stuart-Atlanta line tripped at 14:02 EDT. The EMS Engineer adjusted the model, which by this time had been updated with the 15:05 EDT Harding-Chamberlin 345-kV line trip, and came up with a valid solution.

At 15:32 EDT, FirstEnergy's Hanna-Juniper 345-kV line tripped and locked out. The AEPR continued to malfunction.

At 15:41 EDT, the lights flickered at the FirstEnergy's control facility. This occurred because they had lost grid power and switched over to their emergency power supply.

At 15:42 EDT, a FirstEnergy dispatcher realized that the AEPR was not working and made technical support staff aware of the problem.

Endnotes

1 http://www.nrc.gov/reading-rm/doc-collections/news/2003/ 03-108.html.

2 http://www.fbi.gov/congress/congress03/mefford090403.htm.

3 http://www.fbi.gov/congress/congress03/mefford090403.htm.

10. Recommendations to Prevent or Minimize the Scope of Future Blackouts

Introduction

As reported in previous chapters, the blackout on August 14, 2003, was preventable. It had several direct causes and contributing factors, including:

- Failure to maintain adequate reactive power support
- Failure to ensure operation within secure limits
- Inadequate vegetation management
- Inadequate operator training
- Failure to identify emergency conditions and communicate that status to neighboring systems
- Inadequate regional-scale visibility over the bulk power system.

Further, as discussed in Chapter 7, after each major blackout in North America since 1965, an expert team of investigators has probed the causes of the blackout, written detailed technical reports, and issued lists of recommendations to prevent or minimize the scope of future blackouts. Yet several of the causes of the August 14 blackout are strikingly similar to those of the earlier blackouts. Clearly, efforts to implement earlier recommendations have not been adequate.[1] Accordingly, the recommendations presented below emphasize comprehensiveness, monitoring, training, and enforcement of reliability standards when necessary to ensure compliance.

It is useful to think of the recommendations presented below in terms of four broad themes:

1. Government bodies in the U.S. and Canada, regulators, the North American electricity industry, and related organizations should commit themselves to making adherence to high reliability standards paramount in the planning, design, and operation of North America's vast bulk power systems. Market mechanisms should be used where possible, but in circumstances where conflicts between reliability and commercial objectives cannot be reconciled, they must be resolved in favor of high reliability.[2]

2. Regulators and consumers should recognize that reliability is not free, and that maintaining it requires ongoing investments and operational expenditures by many parties. Regulated companies will not make such outlays without assurances from regulators that the costs will be recoverable through approved electric rates, and unregulated companies will not make such outlays unless they believe their actions will be profitable.[3]

3. Recommendations have no value unless they are implemented. Accordingly, the Task Force emphasizes strongly that North American governments and industry should commit themselves to working together to put into effect the suite of improvements mapped out below. Success in this area will require particular attention to the mechanisms proposed for performance monitoring, accountability of senior management, and enforcement of compliance with standards.

4. The bulk power systems are among the most critical elements of our economic and social infrastructure. Although the August 14 blackout was not caused by malicious acts, a number of security-related actions are needed to enhance reliability.

Over the past decade or more, electricity demand has increased and the North American interconnections have become more densely woven and heavily loaded, over more hours of the day and year. In many geographic areas, the number of single or multiple contingencies that could create serious problems has increased. Operating the grids at higher loadings means greater stress on equipment and a smaller range of options and a shorter period of time for dealing with unexpected problems. The system operator's job has become more challenging, leading to the need for more sophisticated grid management tools and more demanding operator training programs and certification requirements.

The recommendations below focus on changes of many kinds that are needed to ensure reliability, for both the summer of 2004 and for the years to follow. Making these changes will require higher and broader awareness of the importance of reliability, and some of them may require substantial new investments. However, the cost of *not* making these changes, i.e., the cost of chronic large-scale blackouts, would be far higher than the cost of addressing the problem. Estimates of the cost of the August 14 blackout range between $4 and $10 billion (U.S.).[4]

The need for additional attention to reliability is not necessarily at odds with increasing competition and the improved economic efficiency it brings to bulk power markets. Reliability and economic efficiency can be compatible, but this outcome requires more than reliance on the laws of physics and the principles of economics. It requires sustained, focused efforts by regulators, policy makers, and industry leaders to strengthen and maintain the institutions and rules needed to protect both of these important goals. Regulators must ensure that competition does not erode incentives to comply with reliability requirements, and that reliability requirements do not serve as a smokescreen for noncompetitive practices.

The metric for gauging achievement of this goal—making the changes needed to maintain a high level of reliability for the next decade or longer—will be the degree of compliance obtained with the recommendations presented below. The single most important step in the United States is for the U.S. Congress to enact the reliability provisions in pending energy bills (H.R. 6 and S. 2095). If that can be done, many of the actions recommended below could be accomplished readily in the course of implementing the legislation.

Some commenters asserted that the Interim Report did not analyze all factors they believe may have contributed to the August 14 blackout. Implementation of the recommendations presented below will address all remaining issues, through the ongoing work of government bodies and agencies in the U.S. and Canada, the electricity industry, and the non-governmental institutions responsible for the maintenance of electric reliability in North America.

Recommendations

Forty-six numbered recommendations are presented below, grouped into four substantive areas. Some recommendations concern subjects that were addressed in some detail by commenters on the Interim Report or participants in the Task Force's two technical conferences. In such cases, the commenters are listed in the Endnotes section of this chapter. Citation in the endnotes does not necessarily mean that the commenter supports the position expressed in the recommendation. A "table of contents" overview of the recommendations is provided in the text box on pages 141-142.

Group I. Institutional Issues Related to Reliability

1. Make reliability standards mandatory and enforceable, with penalties for noncompliance.[5]

Appropriate branches of government in the United States and Canada should take action as required to make reliability standards mandatory and enforceable, and to provide appropriate penalties for noncompliance.

A. Action by the U.S. Congress

The U.S. Congress should enact reliability legislation no less stringent than the provisions now included in the pending comprehensive energy bills, H.R. 6 and S. 2095. Specifically, these provisions would require that:

- Reliability standards are to be mandatory and enforceable, with penalties for noncompliance.
- Reliability standards should be developed by an independent, international electric reliability organization (ERO) with fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organizational structure. (See text box on NERC and an ERO below.)

Overview of Task Force Recommendations: Titles Only

Group I. Institutional Issues Related to Reliability

1. Make reliability standards mandatory and enforceable, with penalties for noncompliance.
2. Develop a regulator-approved funding mechanism for NERC and the regional reliability councils, to ensure their independence from the parties they oversee.
3. Strengthen the institutional framework for reliability management in North America.
4. Clarify that prudent expenditures and investments for bulk system reliability (including investments in new technologies) will be recoverable through transmission rates.
5. Track implementation of recommended actions to improve reliability.
6. FERC should not approve the operation of new RTOs or ISOs until they have met minimum functional requirements.
7. Require any entity operating as part of the bulk power system to be a member of a regional reliability council if it operates within the council's footprint.
8. Shield operators who initiate load shedding pursuant to approved guidelines from liability or retaliation.
9. Integrate a "reliability impact" consideration into the regulatory decision-making process.
10. Establish an independent source of reliability performance information.
11. Establish requirements for collection and reporting of data needed for post-blackout analyses.
12. Commission an independent study of the relationships among industry restructuring, competition, and reliability.
13. DOE should expand its research programs on reliability-related tools and technologies.
14. Establish a standing framework for the conduct of future blackout and disturbance investigations.

Group II. Support and Strengthen NERC's Actions of February 10, 2004

15. Correct the direct causes of the August 14, 2003 blackout.
16. Establish enforceable standards for maintenance of electrical clearances in right-of-way areas.
17. Strengthen the NERC Compliance Enforcement Program.
18. Support and strengthen NERC's Reliability Readiness Audit Program.
19. Improve near-term and long-term training and certification requirements for operators, reliability coordinators, and operator support staff.
20. Establish clear definitions for *normal, alert* and *emergency* operational system conditions. Clarify roles, responsibilities, and authorities of reliability coordinators and control areas under each condition.
21. Make more effective and wider use of system protection measures.
22. Evaluate and adopt better real-time tools for operators and reliability coordinators.
23. Strengthen reactive power and voltage control practices in all NERC regions.
24. Improve quality of system modeling data and data exchange practices.
25. NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards.
26. Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate.
27. Develop enforceable standards for transmission line ratings.
28. Require use of time-synchronized data recorders.
29. Evaluate and disseminate lessons learned during system restoration.
30. Clarify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages.
31. Clarify that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit. Streamline the TLR process.

(continued on page 142)

Overview of Task Force Recommendations: Titles Only (Continued)

Group III. Physical and Cyber Security of North American Bulk Power Systems

32. Implement NERC IT standards.
33. Develop and deploy IT management procedures.
34. Develop corporate-level IT security governance and strategies.
35. Implement controls to manage system health, network monitoring, and incident management.
36. Initiate U.S.-Canada risk management study.
37. Improve IT forensic and diagnostic capabilities.
38. Assess IT risk and vulnerability at scheduled intervals.
39. Develop capability to detect wireless and remote wireline intrusion and surveillance.
40. Control access to operationally sensitive equipment.
41. NERC should provide guidance on employee background checks.
42. Confirm NERC ES-ISAC as the central point for sharing security information and analysis.
43. Establish clear authority for physical and cyber security.
44. Develop procedures to prevent or mitigate inappropriate disclosure of information.

Group IV. Canadian Nuclear Power Sector

45. The Task Force recommends that the Canadian Nuclear Safety Commission request Ontario Power Generation and Bruce Power to review operating procedures and operator training associated with the use of adjuster rods.
46. The Task Force recommends that the Canadian Nuclear Safety Commission purchase and install backup generation equipment.

- Reliability standards should allow, where appropriate, flexibility to accommodate regional differences, including more stringent reliability requirements in some areas, but regional deviations should not be allowed to lead to lower reliability expectations or performance.
- An ERO-proposed standard or modification to a standard should take effect within the United States upon approval by the Federal Energy Regulatory Commission (FERC).
- FERC should remand to the ERO for further consideration a proposed reliability standard or a modification to a reliability standard that it disapproves of in whole or in part, with explanation for its concerns and rationale.

B. Action by FERC

In the absence of such reliability legislation, FERC should review its statutory authorities under existing law, and to the maximum extent permitted by those authorities, act to enhance reliability by making compliance with reliability standards enforceable in the United States. In doing so, FERC should consult with state regulators, NERC, and the regional reliability councils to determine whether certain enforcement practices now in use in some parts of the U.S. and Canada might be applied more broadly. For example, in the Western U.S. and Canada, many members of the Western Electricity Coordinating Council (WECC) include clauses in contracts for the purchase of wholesale power that require the parties to comply with reliability standards. In the areas of the U.S. and Canada covered by the Northeast Power Coordinating Council (NPCC), parties found not to be in compliance with NERC and NPCC reliability requirements are subject to escalating degrees of scrutiny by their peers and the public. Both of these approaches have had positive effects. FERC should examine other approaches as well, and work with state regulatory authorities to ensure

NERC and the ERO

If the proposed U.S. reliability legislation passes, the North American Electric Reliability Council (NERC) may undertake various organizational changes and seek recognition as the electric reliability organization (ERO) called for in H.R. 6 and S. 2095. For simplicity of presentation, the many forward-looking references below to "NERC" are intended to apply to the ERO if the legislation is passed, and to NERC if the legislation is not passed.

that any other appropriate actions to make reliability standards enforceable are taken.

Action by FERC under its existing authorities would not lessen the need for enactment of reliability legislation by the Congress. Many U.S. parties that should be required by law to comply with reliability requirements are not subject to the Commission's full authorities under the Federal Power Act.

C. Action by Appropriate Authorities in Canada

The interconnected nature of the transmission grid requires that reliability standards be identical or compatible on both sides of the Canadian/U.S. border. Several provincial governments in Canada have already demonstrated support for mandatory and enforceable reliability standards and have either passed legislation or have taken steps to put in place the necessary framework for implementing such standards in Canada. The federal and provincial governments should work together and with appropriate U.S. authorities to complete a framework to ensure that identical or compatible standards apply in both countries, and that means are in place to enforce them in all interconnected jurisdictions.

D. Joint Actions by U.S. and Canadian Governments

International coordination mechanisms should be developed between the governments in Canada and the United States to provide for government oversight of NERC or the ERO, and approval and enforcement of reliability standards.

E. Memoranda of Understanding between U.S. or Canadian Government Agencies and NERC

Government agencies in both countries should decide (individually) whether to develop a memorandum of understanding (MOU) with NERC that would define the agency's working relationship with NERC, government oversight of NERC activities if appropriate, and the reliability responsibilities of the signatories.

2. Develop a regulator-approved mechanism for funding NERC and the regional reliability councils, to ensure their independence from the parties they oversee.[6]

U.S. and Canadian regulatory authorities should work with NERC, the regional councils, and the industry to develop and implement a new funding mechanism for NERC and the regional councils based on a surcharge in transmission rates. The purpose would be to ensure that NERC and the councils are appropriately funded to meet their changing responsibilities without dependence on the parties that they oversee. Note: Implementation of this recommendation should be coordinated with the review called for in Recommendation 3 concerning the future role of the regional councils.

NERC's current $13 million/year budget is funded as part of the dues that transmission owners, generators, and other market participants pay to the ten regional reliability councils, which then fund NERC. This arrangement makes NERC subject to the influence of the reliability councils, which are in turn subject to the influence of their control areas and other members. It also compromises the independence of both NERC and the councils in relation to the entities whose actions they oversee, and makes it difficult for them to act forcefully and objectively to maintain the reliability of the North American bulk power system. Funding NERC and the councils through a transmission rate surcharge administered and disbursed under regulatory supervision would enable the organizations to be more independent of the industry, with little impact on electric bills. The dues that companies pay to the regional councils are passed through to electricity customers today, so the net impacts on customer bills from shifting to a rate surcharge would be minimal.

Implementation of the recommendations presented in this report will involve a substantial increase in NERC's functions and responsibilities, and require an increase in NERC's annual budget. The additional costs, however, would be small in comparison to the cost of a single major blackout.

3. Strengthen the institutional framework for reliability management in North America.[7]

FERC, DOE and appropriate authorities in Canada should work with the states, NERC, and the industry, to evaluate and develop appropriate modifications to the existing institutional framework for reliability management. In particular, the affected government agencies should:

A. Commission an independent review by qualified experts in organizational design and management to address issues concerning how best to structure an international reliability organization for the long term.

B. **Based in part on the results of that review, develop metrics for gauging the adequacy of NERC's performance, and specify the functions of the NERC Board of Trustees and the procedure for selecting the members of the Board.**

C. **Examine and clarify the future role of the regional reliability councils, with particular attention to their mandate, scope, structure, responsibilities, and resource requirements.**

D. **Examine NERC's proposed Functional Model and set minimum requirements under which NERC would certify applicants' qualifications to perform critical functions.**

E. **Request NERC and the regional councils to suspend designation of any new control areas (or sub-control areas) until the minimum requirements in section D (above) have been established, unless an applicant shows that such designation would significantly enhance reliability.**

F. **Determine ways to enhance reliability operations in the United States through simplified organizational boundaries and resolution of seams issues.**

A and B. Reshaping NERC

The far-reaching organizational changes in the North American electricity industry over the past decade have already induced major changes in the nature of NERC as an organization. However, the process of change at NERC is far from complete. Important additional changes are needed such as the shift to enforceable standards, development of an effective monitoring capability, and funding that is not dependent on the industry. These changes will strengthen NERC as an organization. In turn, to properly serve overarching public policy concerns, this strengthening of NERC's capabilities will have to be balanced with increased government oversight, more specific metrics for gauging NERC's performance as an organization, and greater transparency concerning the functions of its senior management team (including its Board of Trustees) and the procedures by which those individuals are selected. The affected government agencies should jointly commission an independent review of these and related issues to aid them in making their respective decisions.

C. The Role of the Regional Reliability Councils

North America's regional reliability councils have evolved into a disparate group of organizations with varying responsibilities, expertise, roles, sizes and resources. Some have grown from a reliability council into an ISO or RTO (ERCOT and SPP), some span less than a single state (FRCC and ERCOT) while others cover many states and provinces and cross national boundaries (NPCC and WECC). Several cross reliability coordinator boundaries. It is time to evaluate the appropriate size and scope of a regional council, the specific tasks that it should perform, and the appropriate level of resources, expertise, and independence that a regional reliability council needs to perform those tasks effectively. This evaluation should also address whether the councils as currently constituted are appropriate to meet future reliability needs.

D. NERC's Functional Model

The transition to competition in wholesale power markets has been accompanied by increasing diversity in the kinds of entities that need to be in compliance with reliability standards. Rather than resist or attempt to influence this evolution, NERC's response—through the Functional Model—has been to seek a means of enabling reliability to be maintained under virtually any institutional framework. The Functional Model identifies sixteen basic functions associated with operating the bulk electric systems and maintaining reliability, and the capabilities that an organization must have in order to perform a given function. (See Functional Model text box below.)

NERC acknowledges that maintaining reliability in some frameworks may be more difficult or more expensive than in others, but it stresses that as long as some responsible party addresses each function and the rules are followed, reliability will be preserved. By implication, the pros and cons of alternative institutional frameworks in a given region—which may affect aspects of electric industry operations other than reliability—are matters for government agencies to address, not NERC.

One of the major purposes of the Functional Model is to create a vehicle through which NERC will be able to identify an entity responsible for performing each function in every part of the three North American interconnections. NERC considers four of the sixteen functions to be especially critical for reliability. For these functions, NERC intends, upon application by an entity, to review the entity's capabilities, and if appropriate, certify that the entity has the qualifications to perform that function within the specified geographic area. For the other twelve functions, NERC proposes to "register" entities as responsible for a given function in a given area, upon application.

All sixteen functions are presently being performed to varying degrees by one entity or another today in all areas of North America. Frequently an entity performs a combination of functions, but there is great variety from one region to another in how the functions are bundled and carried out. Whether all of the parties who are presently performing the four critical functions would meet NERC's requirements for certification is not known, but the proposed process provides a means of identifying any weaknesses that need to be rectified.

At present, after protracted debate, the Functional Model appears to have gained widespread but cautious support from the diverse factions across the industry, while the regulators have not taken a position. In some parts of North America, such as the Northeast, large regional organizations will probably be certified to perform all four of the critical functions for their respective areas. In other areas, capabilities may remain less aggregated, and the institutional structure may remain more complex.

Sixteen Functions in NERC's Functional Model

- **Operating Reliability**
- **Planning Reliability**
- **Balancing** (generation and demand)
- **Interchange**
- Transmission service
- Transmission ownership
- Transmission operations
- Transmission planning
- Resource planning
- Distribution
- Generator ownership
- Generator operations
- Load serving
- Purchasing and selling
- Standards development
- Compliance monitoring

NERC regards the four functions shown above in bold as especially critical to reliability. Accordingly, it proposes to certify applicants that can demonstrate that they have the capabilities required to perform those functions. The Operating Reliability authority would correspond to today's reliability coordinator, and the Balancing authority to today's control area operator.

Working with NERC and the industry, FERC and authorities in Canada should review the Functional Model to ensure that operating hierarchies and entities will facilitate, rather than hinder, efficient reliability operations. At a minimum, the review should identify ways to eliminate inappropriate commercial incentives to retain control area status that do not support reliability objectives; address operational problems associated with institutional fragmentation; and set minimum requirements with respect to the capabilities requiring NERC certification, concerning subjects such as:

1. Fully operational backup control rooms.
2. System-wide (or wider) electronic map boards or functional equivalents, with data feeds that are independent of the area's main energy management system (EMS).
3. Real-time tools that are to be available to the operator, with backups. (See Recommendation 22 below for more detail concerning minimum requirements and guidelines for real-time operating tools.)
4. SCADA and EMS requirements, including backup capabilities.
5. Training programs for all personnel who have access to a control room or supervisory responsibilities for control room operations. (See Recommendation 19 for more detail on the Task Force's views regarding training and certification requirements.)
6. Certification requirements for control room managers and staff.

E. Designation of New Control Areas

Significant changes in the minimum functional requirements for control areas (or balancing authorities, in the context of the Functional Model) may result from the review called for above. Accordingly, the Task Force recommends that regulatory authorities should request NERC and the regional councils not to certify any new control areas (or sub-control areas) until the appropriate regulatory bodies have approved the minimum functional requirements for such bodies, unless an applicant shows that such designation would significantly enhance reliability.

F. Boundary and Seam Issues and Minimum Functional Requirements

Some observers believe that some U.S. regions have too many control areas performing one or more of the four critical reliability functions. In many cases, these entities exist to retain commercial advantages associated with some of these functions. The resulting institutional fragmentation and decentralization of control leads to a higher number of operating contacts and seams, complex coordination requirements, misalignment of control areas with other electrical boundaries and/or operating hierarchies, inconsistent practices and tools, and increased compliance monitoring requirements. These consequences hamper the efficiency and reliability of grid operations.

As shown above (text box on page 14), MISO, as reliability coordinator for its region, is responsible for dealing with 37 control areas, whereas PJM now spans 9 control areas, ISO-New England has 2, and the New York ISO, Ontario's IMO, Texas' ERCOT, and Québec's Trans-Energie are themselves the control area operators for their respective large areas. Moreover, it is not clear that small control areas are financially able to provide the facilities and services needed to perform control area functions at the level needed to maintain reliability. This concern applies also to the four types of entities that NERC proposes to certify under the Functional Model (i.e., Reliability Authority, Planning Authority, Balancing Authority, and Interchange Authority).

For the long term, the regulatory agencies should continue to seek ways to ensure that the regional operational frameworks that emerge through the implementation of the Functional Model promote reliable operations. Any operational framework will represent some combination of tradeoffs, but reliability is a critically important public policy objective and should be a primary design criterion.

4. Clarify that prudent expenditures and investments for bulk system reliability (including investments in new technologies) will be recoverable through transmission rates.[8]

FERC and appropriate authorities in Canada should clarify that prudent expenditures and investments by regulated companies to maintain or improve bulk system reliability will be recoverable through transmission rates.

In the U.S., FERC and DOE should work with state regulators to identify and resolve issues related to the recovery of reliability costs and investments through retail rates. Appropriate authorities in Canada should determine whether similar efforts are warranted.

Companies will not make the expenditures and investments required to maintain or improve the reliability of the bulk power system without credible assurances that they will be able to recover their costs.

5. Track implementation of recommended actions to improve reliability.[9]

In the requirements issued on February 10, 2004, NERC announced that it and the regional councils would establish a program for documenting completion of recommendations resulting from the August 14 blackout and other historical outages, as well as NERC and regional reports on violations of reliability standards, results of compliance audits, and lessons learned from system disturbances. The regions are to report on a quarterly basis to NERC.

In addition, NERC intends to initiate by January 1, 2005 a reliability performance monitoring function that will evaluate and report on trends in bulk electric system reliability performance.

The Task Force supports these actions strongly. However, many of the Task Force's recommendations pertain to government bodies as well as NERC. Accordingly:

A. Relevant agencies in the U.S. and Canada should cooperate to establish mechanisms for tracking and reporting to the public on implementation actions in their respective areas of responsibility.

B. NERC should draw on the above-mentioned quarterly reports from its regional councils to prepare annual reports to FERC, appropriate authorities in Canada, and the public on the status of the industry's compliance with recommendations and important trends in electric system reliability performance.

The August 14 blackout shared a number of contributing factors with prior large-scale blackouts, confirming that the lessons and recommendations from earlier blackouts had not been adequately implemented, at least in some geographic areas. Accordingly, parallel and coordinated efforts are needed by the relevant government agencies and NERC to track the implementation of recommendations by governments and the electricity industry. WECC and NPCC have already established programs that could serve as models for tracking implementation of recommendations.

6. FERC should not approve the operation of a new RTO or ISO until the applicant has met the minimum functional requirements for reliability coordinators.

The events of August 14 confirmed that MISO did not yet have all of the functional capabilities required to fulfill its responsibilities as reliability coordinator for the large area within its footprint. FERC should not authorize a new RTO or ISO to become operational until the RTO or ISO has verified that all critical reliability capabilities will be functional upon commencement of RTO or ISO operations.

7. Require any entity operating as part of the bulk power system to be a member of a regional reliability council if it operates within the council's footprint.[10]

The Task Force recommends that FERC and appropriate authorities in Canada be empowered through legislation, if necessary, to require all entities that operate as part of the bulk electric system to certify that they are members of the regional reliability council for all NERC regions in which they operate.

This requirement is needed to ensure that all relevant parties are subject to NERC standards, policies, etc., in all NERC regions in which they operate. Action by the Congress or legislative bodies in Canada may be necessary to provide appropriate authority.

8. Shield operators who initiate load shedding pursuant to approved guidelines from liability or retaliation.[11]

Legislative bodies and regulators should: 1) establish that operators (whether organizations or individuals) who initiate load shedding pursuant to operational guidelines are not subject to liability suits; and 2) affirm publicly that actions to shed load pursuant to such guidelines are not indicative of operator failure.

Timely and sufficient action to shed load on August 14 would have prevented the spread of the blackout beyond northern Ohio. NERC has directed all the regional councils in all areas of North America to review the applicability of plans for under-voltage load shedding, and to support the development of such capabilities where they would be beneficial. However, organizations and individual operators may hesitate to initiate such actions in appropriate circumstances without assurances that they will not be subject to liability suits or other forms of retaliation, provided their action is pursuant to previously approved guidelines.

9. Integrate a "reliability impact" consideration into the regulatory decision-making process.[12]

The Task Force recommends that FERC, appropriate authorities in Canada, and state regulators integrate a formal reliability impact consideration into their regulatory decision-making to ensure that their actions or initiatives either improve or at minimum do no harm to reliability.

Regulatory actions can have unintended consequences. For example, in reviewing proposed utility company mergers, FERC's primary focus has been on financial and rate issues, as opposed to the reliability implications of such mergers. To minimize unintended harm to reliability, and aid the improvement of reliability where appropriate, the Task Force recommends that regulators incorporate a formal reliability impact consideration into their decision processes. At the same time, regulators should be watchful for use of alleged reliability impacts as a smokescreen for anti-competitive or discriminatory behavior.

10. Establish an independent source of reliability performance information.[13]

The U.S. Department of Energy's Energy Information Administration (EIA), in coordination with other interested agencies and data sources (FERC, appropriate Canadian government agencies, NERC, RTOs, ISOs, the regional councils, transmission operators, and generators) should establish common definitions and information collection standards. If the necessary resources can be identified, EIA should expand its current activities to include information on reliability performance.

Energy policy makers and a wide range of economic decision makers need objective, factual information about basic trends in reliability performance. EIA and the other organizations cited above should identify information gaps in federal data collections covering reliability performance and physical characteristics. Plans to fill those gaps should be developed, and the associated resource requirements determined. Once those resources have been acquired, EIA should publish information on trends, patterns, costs, etc. related to reliability performance.

11. Establish requirements for collection and reporting of data needed for post-blackout analyses.

FERC and appropriate authorities in Canada should require generators, transmission owners, and other relevant entities to collect and report data that may be needed for analysis of blackouts and other grid-related disturbances.

The investigation team found that some of the data needed to analyze the August 14 blackout fully was not collected at the time of the events, and thus could not be reported. Some of the data that was reported was based on incompatible definitions and formats. As a result, there are aspects of the blackout, particularly concerning the evolution of the cascade, that may never be fully explained. FERC, EIA and appropriate authorities in Canada should consult with NERC, key members of the investigation team, and the industry to identify information gaps, adopt common definitions, and establish filing requirements.

12. Commission an independent study of the relationships among industry restructuring, competition, and reliability.[14]

DOE and Natural Resources Canada should commission an independent study of the relationships among industry restructuring, competition in power markets, and grid reliability, and how those relationships should be managed to best serve the public interest.

Some participants at the public meetings held in Cleveland, New York and Toronto to review the Task Force's Interim Report expressed the view that the restructuring of electricity markets for competition in many jurisdictions has, itself, increased the likelihood of major supply interruptions. Some of these commenters assert that the transmission system is now being used to transmit power over distances and at volumes that were not envisioned when the system was designed, and that this functional shift has created major risks that have not been adequately addressed. Indeed, some commenters believe that restructuring was a major cause of the August 14 blackout.

The Task Force believes that the Interim Report accurately identified the primary causes of the blackout. It also believes that had existing reliability requirements been followed, either the disturbance in northern Ohio that evolved on August 14 into a blackout would not have occurred, or it would have been contained within the FE control area.

Nevertheless, as discussed at the beginning of this chapter, the relationship between competition in power markets and reliability is both important and complex, and careful management and sound rules are required to achieve the public policy goals of reasonable electricity prices and high reliability. At the present stage in the evolution of these markets, it is worthwhile for DOE and Natural Resources Canada (in consultation with FERC and the Canadian Council of Energy Ministers) to commission an independent expert study to provide advice on how to achieve and sustain an appropriate balance in this important area.

Among other things, this study should take into account factors such as:

- Historical and projected load growth
- Location of new generation in relation to old generation and loads
- Zoning and NIMBY[15] constraints on siting of generation and transmission
- Lack of new transmission investment and its causes
- Regional comparisons of impact of wholesale electric competition on reliability performance and on investments in reliability and transmission
- The financial community's preferences and their effects on capital investment patterns
- Federal vs. state jurisdictional concerns
- Impacts of state caps on retail electric rates
- Impacts of limited transmission infrastructure on energy costs, transmission congestion, and reliability

- Trends in generator fuel and wholesale electricity prices
- Trends in power flows, line losses, voltage levels, etc.

13. DOE should expand its research programs on reliability-related tools and technologies.[16]

DOE should expand its research agenda, and consult frequently with Congress, FERC, NERC, state regulators, Canadian authorities, universities, and the industry in planning and executing this agenda.

More investment in research is needed to improve grid reliability, with particular attention to improving the capabilities and tools for system monitoring and management. Research on reliability issues and reliability-related technologies has a large public-interest component, and government support is crucial. DOE already leads many research projects in this area, through partnerships with industry and research under way at the national laboratories and universities. DOE's leadership and frequent consultation with many parties are essential to ensure the allocation of scarce research funds to urgent projects, bring the best talent to bear on such projects, and enhance the dissemination and timely application of research results.

Important areas for reliability research include but are not limited to:

- Development of practical real-time applications for wide-area system monitoring using phasor measurements and other synchronized measuring devices, including post-disturbance applications.
- Development and use of enhanced techniques for modeling and simulation of contingencies, blackouts, and other grid-related disturbances.
- Investigation of protection and control alternatives to slow or stop the spread of a cascading power outage, including demand response initiatives to slow or halt voltage collapse.
- Re-evaluation of generator and customer equipment protection requirements based on voltage and frequency phenomena experienced during the August 14, 2003, cascade.
- Investigation of protection and control of generating units, including the possibility of multiple steps of over-frequency protection and possible effects on system stability during major disturbances.
- Development of practical human factors guidelines for power system control centers.
- Study of obstacles to the economic deployment of demand response capability and distributed generation.
- Investigation of alternative approaches to monitoring right-of-way vegetation management.
- Study of air traffic control, the airline industry, and other relevant industries for practices and ideas that could reduce the vulnerability of the electricity industry and its reliability managers to human error.

Cooperative and complementary research and funding between nations and between government and industry efforts should be encouraged.

14. Establish a standing framework for the conduct of future blackout and disturbance investigations.[17]

The U.S., Canadian, and Mexican governments, in consultation with NERC, should establish a standing framework for the investigation of future blackouts, disturbances, or other significant grid-related incidents.

Fortunately, major blackouts are not frequent, which makes it important to study such events carefully to learn as much as possible from the experience. In the weeks immediately after August 14, important lessons were learned pertaining not only to preventing and minimizing future blackouts, but also to the efficient and fruitful investigation of future grid-related events.

Appropriate U.S., Canadian, and Mexican government agencies, in consultation with NERC and other organizations, should prepare an agreement that, among other considerations:

- Establishes criteria for determining when an investigation should be initiated.
- Establishes the composition of a task force to provide overall guidance for the inquiry. The task force should be international if the triggering event had international consequences.
- Provides for coordination with state and provincial governments, NERC and other appropriate entities.

- Designates agencies responsible for issuing directives concerning preservation of records, provision of data within specified periods to a data warehouse facility, conduct of onsite interviews with control room personnel, etc.
- Provides guidance on confidentiality of data.
- Identifies types of expertise likely to be needed on the investigation team.

Group II. Support and Strengthen NERC's Actions of February 10, 2004

On February 10, 2004, after taking the findings of the Task Force's investigation into the August 14, 2003, blackout into account, the NERC Board of Trustees approved a series of actions and strategic and technical initiatives intended to protect the reliability of the North American bulk electric system. (See Appendix D for the full text of the Board's statement of February 10.) Overall, the Task Force supports NERC's actions and initiatives strongly. On some subjects, the Task Force advocates additional measures, as shown in the next 17 recommendations.

15. Correct the direct causes of the August 14, 2003 blackout.[18]

NERC played an important role in the Task Force's blackout investigation, and as a result of the findings of the investigation, NERC issued directives on February 10, 2004 to FirstEnergy, MISO, and PJM to complete a series of remedial actions by June 30, 2004 to correct deficiencies identified as factors contributing to the blackout of August 14, 2003. (For specifics on the actions required by NERC, see Appendix D.)

The Task Force supports and endorses NERC's near-term requirements strongly. It recommends the addition of requirements pertaining to ECAR, and several other additional elements, as described below.

A. Corrective Actions to Be Completed by FirstEnergy by June 30, 2004

The full text of the remedial actions NERC has required that FirstEnergy (FE) complete by June 30 is provided in Appendix D. The Task Force recommends the addition of certain elements to these requirements, as described below.

1. Examination of Other FE Service Areas

The Task Force's investigation found severe reactive power and operations criteria deficiencies in the Cleveland-Akron area.

NERC:

Specified measures required in that area to help ensure the reliability of the FE system and avoid undue risks to neighboring systems. However, the blackout investigation did not examine conditions in FE service areas in other states.

Task Force:

Recommends that NERC require FE to review its entire service territory, in all states, to determine whether similar vulnerabilities exist and require prompt attention. This review should be completed by June 30, 2004, and the results reported to FERC, NERC, and utility regulatory authorities in the affected states.

2. Interim Voltage Criteria

NERC:

Required that FE, consistent with or as part of a study ordered by FERC on December 24, 2003,[19] determine the minimum acceptable location-specific voltages at all 345 kV and 138 kV buses and all generating stations within the FE control area (including merchant plants). Further, FE is to determine the minimum dynamic reactive reserves that must be maintained in local areas to ensure that these minimum voltages are met following contingencies studied in accordance with ECAR Document 1.[20] Criteria and minimum voltage requirements must comply with NERC planning criteria, including Table 1A, Category C3, and Operating Policy 2.[21]

Task Force:

Recommends that NERC appoint a team, joined by representatives from FERC and the Ohio Public Utility Commission, to review and approve all such criteria.

3. FE Actions Based on FERC-Ordered Study

NERC:

Required that when the FERC-ordered study is completed, FE is to adopt the planning and operating criteria determined as a result of that study and update the operating criteria and procedures for its system operators. If the study indicates a need for system reinforcement, FE is to develop a plan for developing such resources as soon as practical and develop operational procedures or other mitigating programs to maintain safe operating conditions until such time that the necessary system reinforcements can be made.

Task Force:

Recommends that a team appointed by NERC and joined by representatives from FERC and the Ohio Public Utility Commission should review and approve this plan.

4. Reactive Resources

NERC:

Required that FE inspect all reactive resources, including generators, and ensure that all are fully operational. FE is also required to verify that all installed capacitors have no blown fuses and that at least 98% of installed capacitors (69 kV and higher) are available for service during the summer of 2004.

Task Force:

Recommends that NERC also require FE to confirm that all non-utility generators in its area have entered into contracts for the sale of generation committing them to producing increased or maximum reactive power when called upon by FE or MISO to do so. Such contracts should ensure that the generator would be compensated for revenue losses associated with a reduction in real power sales in order to increase production of reactive power.

5. Operational Preparedness and Action Plan

NERC:

Required that FE prepare and submit to ECAR an Operational Preparedness and Action Plan to ensure system security and full compliance with NERC and planning and operating criteria, including ECAR Document 1.

Task Force:

Recommends that NERC require copies of this plan to be provided to FERC, DOE, the Ohio Public Utility Commission, and the public utility commissions in other states in which FE operates. The Task Force also recommends that NERC require FE to invite its system operations partners—control areas adjacent to FE, plus MISO, ECAR, and PJM—to participate in the development of the plan and agree to its implementation in all aspects that could affect their respective systems and operations.

6. Emergency Response Resources

NERC:

Required that FE develop a capability to reduce load in the Cleveland-Akron area by 1500 MW within ten minutes of a directive to do so by MISO or the FE system operator. Such a capability may be provided by automatic or manual load shedding, voltage reduction, direct-controlled commercial or residential load management, or any other method or combination of methods capable of achieving the 1500 MW of reduction in ten minutes without adversely affecting other interconnected systems. The amount of required load reduction capability may be modified to an amount shown by the FERC-ordered study to be sufficient for response to severe contingencies *and* if approved by ECAR and NERC.

Task Force:

Recommends that NERC require MISO's approval of any change in the amount of required load reduction capability. It also recommends that NERC require FE's load reduction plan to be shared with the Ohio Public Utilities Commission and that FE should communicate with all communities in the affected areas about the plan and its potential consequences.

7. Emergency Response Plan

NERC:

Required that FE develop an emergency response plan, including arrangements for deploying the load reduction capabilities noted above. The plan is to include criteria for determining the existence of an emergency and identify various possible states of emergency. The plan is to include detailed operating procedures and communication protocols with all the relevant entities including MISO, FE operators, and market participants within the FE area that have an ability to vary generation output or shed load upon orders from FE operators. The plan should include procedures for load restoration after the declaration that the FE system is no longer in an emergency operating state.

Task Force:

Recommends that NERC require FE to offer its system operations partners—i.e., control areas adjacent to FE, plus MISO, ECAR, and PJM—an opportunity to contribute to the development of the plan and agree to its key provisions.

8. Operator Communications

NERC:

Required that FE develop communications procedures for FE operating personnel to use within FE, with MISO and neighboring systems, and others. The procedure and the operating environment within the FE system control center should allow control room staff to focus on reliable system operations and avoid distractions such as calls from customers and others who are not responsible for operation of a portion of the transmission system.

Task Force:

Recommends that NERC require these procedures to be shared with and agreed to by control areas adjacent to FE, plus MISO, ECAR, and PJM, and any other affected system operations partners, and that these procedures be tested in a joint drill.

9. Reliability Monitoring and System Management Tools

NERC:

Required that FE ensure that its state estimator and real-time contingency analysis functions are used to execute reliably full contingency analyses automatically every ten minutes or on demand, and used to notify operators of potential first contingency violations.

Task Force:

Recommends that NERC also require FE to ensure that its information technology support function does not change the effectiveness of reliability monitoring or management tools in any way without the awareness and consent of its system operations staff.

10. GE XA21 System Updates and Transition to New Energy Management System

NERC:

Required that until FE replaces its GE XA21 Energy Management System, FE should implement all current known fixes for the GE XA21 system necessary to ensure reliable and stable operation of critical reliability functions, and particularly to correct the alarm processor failure that occurred on August 14, 2003.

Task Force:

Recommends that NERC require FE to design and test the transition to its planned new energy management system to ensure that the system functions effectively, that the transition is made smoothly, that the system's operators are adequately trained, and that all operating partners are aware of the transition.

11. Emergency Preparedness Training for Operators

NERC:

Required that all reliability coordinators, control areas, and transmission operators provide at least five days of training and drills using realistic simulation of system emergencies for each staff person with responsibility for the real-time operation or reliability monitoring of the bulk electric system. This system emergency training is in addition to other training requirements. The term "realistic simulation" includes a variety of tools and methods that present operating personnel with situations to improve and test diagnostic and decision-making skills in an environment that resembles expected conditions during a particular type of system emergency.

Task Force:

Recommends that to provide effective training before June 30, 2004, NERC should require FE to consider seeking the assistance of another control area or reliability coordinator known to have a quality training program (such as IMO or ISO-New England) to provide the needed training with appropriate FE-specific modifications.

B. Corrective Actions to be Completed by MISO by June 30, 2004

1. Reliability Tools

NERC:

Required that MISO fully implement and test its topology processor to provide its operating personnel a real-time view of the system status for all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems. Alarms should be provided for operators for all critical transmission line outages and voltage violations. MISO is to establish a means of exchanging outage information with its members and adjacent systems such that the MISO state estimator has accurate and timely information to perform as designed. MISO is to fully implement and test its state estimation and real-time contingency analysis tools to ensure they can operate reliably no less than every ten minutes. MISO is to provide backup capability for all functions critical to reliability.

Task Force:

Recommends that NERC require MISO to ensure that its information technology support staff does not change the effectiveness of reliability monitoring or management tools in any way without the awareness and consent of its system operations staff.

2. Operating Agreements

NERC:

Required that MISO reevaluate its operating agreements with member entities to verify its authority to address operating issues, including voltage and reactive management, voltage scheduling, the deployment and redispatch of real and reactive reserves for emergency response, and the authority to direct actions during system emergencies, including shedding load.

Task Force:

Recommends that NERC require that any problems or concerns related to these operating issues be raised promptly with FERC and MISO's members for resolution.

C. Corrective Actions to be Completed by PJM by June 30, 2004

NERC:

Required that PJM reevaluate and improve its communications protocols and procedures between PJM and its neighboring control areas and reliability coordinators.

Task Force:

Recommends that NERC require definitions and usages of key terms be standardized, and non-essential communications be minimized during disturbances, alerts, or emergencies. NERC should also require PJM, MISO, and their member companies to conduct one or more joint drills using the new communications procedures.

D. Task Force Recommendations for Corrective Actions to be Completed by ECAR by August 14, 2004

1. Modeling and Assessments

Task Force:

Recommends that NERC require ECAR to reevaluate its modeling procedures, assumptions, scenarios and data for seasonal assessments and extreme conditions evaluations. ECAR should consult with an expert team appointed by NERC—joined by representatives from FERC, DOE, interested state commissions, and MISO—to develop better modeling procedures and scenarios, and obtain review of future assessments by the expert team.

2. Verification of Data and Assumptions

Task Force:

Recommends that NERC require ECAR to reexamine and validate all data and model assumptions against current physical asset capabilities and match modeled assets (such as line characteristics and ratings, and generator reactive power output capabilities) to current operating study assessments.

3. Ensure Consistency of Members' Data

Task Force:

Recommends that NERC require ECAR to conduct a data validation and exchange exercise to be sure that its members are using accurate, consistent, and current physical asset characteristics and capabilities for both long-term and seasonal assessments and operating studies.

E. Task Force Recommendation for Corrective Actions to be Completed by Other Parties by June 30, 2004

Task Force:

Recommends that NERC require each North American reliability coordinator, reliability council, control area, and transmission company not directly addressed above to review the actions required above and determine whether it has adequate system facilities, operational procedures, tools, and training to ensure reliable operations for the summer of 2004. If any entity finds that improvements are needed, it should immediately undertake the needed improvements, and coordinate them with its neighbors and partners as necessary.

The Task Force also recommends that FERC and government agencies in Canada require all entities under their jurisdiction who are users of GE/Harris XA21 Energy Management Systems to consult the vendor and ensure that appropriate actions have been taken to avert any recurrence of the malfunction that occurred on FE's system on August 14.

16. Establish enforceable standards for maintenance of electrical clearances in right-of-way areas.[22]

On February 10, the NERC Board directed the NERC Compliance Program and the regional councils to initiate a joint program for reporting all bulk electric system transmission line trips resulting from vegetation contact. Based on the results of these filings, NERC is to consider the development of minimum line clearance standards to ensure reliability.

The Task Force believes that more aggressive action is warranted. NERC should work with FERC, appropriate authorities in Canada, state regulatory agencies, the Institute of Electrical and Electronic Engineers (IEEE), utility arborists, and other experts from the US and Canada to develop clear, unambiguous standards pertaining to maintenance of safe clearances of transmission lines from obstructions in the lines' right-of-way areas, and to develop a mechanism to verify compliance with the standards and impose penalties for noncompliance.

Ineffective vegetation management was a major cause of the August 14, 2003, blackout and it was also a causal factor in other large-scale North American outages such as those that occurred in the summer of 1996 in the western United States. Maintaining transmission line rights-of-way, including maintaining safe clearances of energized lines from vegetation, man-made structures, bird nests, etc., requires substantial expenditures in many areas of North America. However, such maintenance is a critical investment for ensuring a reliable electric system. For a review of current issues pertaining to utility vegetation management programs, see *Utility Vegetation Management Final Report*, March 2004.[23]

NERC does not presently have standards for right-of-way maintenance. However, it has standards requiring that line ratings be set to maintain safe clearances from all obstructions. Line rating standards should be reviewed to ensure that they are sufficiently clear and explicit. In the United States, National Electrical Safety Code (NESC) rules specify safety clearances required for overhead conductors from grounded objects and other types of obstructions, but those rules are subject to broad interpretation. Several states have adopted their own electrical safety codes and similar codes apply in Canada and its provinces. A mechanism is needed to verify compliance with these requirements and to penalize noncompliance.

A. Enforceable Standards

NERC should work with FERC, government agencies in Canada, state regulatory agencies, the Institute of Electrical and Electronic Engineers (IEEE), utility arborists, and other experts from the U.S. and Canada to develop clear, unambiguous standards pertaining to maintenance of safe clearances of transmission lines from obstructions in the lines' right-of-way areas, and procedures to verify compliance with the standards. States, provinces, and local governments should remain free to set more specific or higher standards as they deem necessary for their respective areas.

B. Right-of-Way Management Plan

NERC should require each bulk electric transmission operator to publish annually a proposed right-of-way management plan on its public website, and a report on its right-of-way management activities for the previous year. The management plan should include the planned frequency of actions such as right-of-way trimming, herbicide treatment, and inspections, and the report should give the dates when the rights-of-way in a given district were last inspected and corrective actions taken.

C. Requirement to Report Outages Due to Ground Faults in Right-of-Way Areas

Beginning with an effective date of March 31, 2004, NERC should require each transmission owner/operator to submit quarterly reports of all ground-fault line trips, including their causes, on lines of 115 kV and higher in its footprint to the regional councils. Failure to report such trips should lead to an appropriate penalty. Each regional council should assemble a detailed annual report on ground fault line trips and their causes in its area to FERC, NERC, DOE, appropriate authorities in Canada, and state regulators no later than March 31 for the preceding year, with the first annual report to be filed in March 2005 for calendar year 2004.

D. Transmission-Related Vegetation Management Expenses, if Prudently Incurred, Should be Recoverable through Electric Rates

The level of activity in vegetation management programs in many utilities and states has fluctuated widely from year to year, due in part to inconsistent funding and varying management support. Utility managers and regulators should recognize the importance of effective vegetation management to transmission system reliability, and that changes in vegetation management may be needed in response to weather, insect infestations, and other factors. Transmission vegetation management programs should be consistently funded and proactively managed to maintain and improve system reliability.

17. Strengthen the NERC Compliance Enforcement Program.

On February 10, 2004, the NERC Board of Trustees approved directives to the regional reliability councils that will significantly strengthen NERC's existing Compliance Enforcement Program. The Task Force supports these directives strongly, and recommends certain additional actions, as described below.[24]

A. Reporting of Violations

NERC:

Requires each regional council to report to the NERC Compliance Enforcement Program within one month of occurrence all "significant violations" of NERC operating policies and planning standards and regional standards, whether verified or still under investigation by the regional council. (A "significant violation" is one that could directly reduce the integrity of the interconnected power systems or otherwise cause unfavorable risk to the interconnected power systems.) In addition, each regional council is to report quarterly to NERC, in a format prescribed by NERC, all violations of NERC and regional reliability standards.

Task Force:

Recommends that NERC require the regional councils' quarterly reports and reports on significant violations be filed as public documents with FERC and appropriate authorities in Canada, at the same time that they are sent to NERC.

B. Enforcement Action by NERC Board

NERC:

After being presented with the results of the investigation of a significant violation, the Board is to require an offending organization to correct the violation within a specified time. If the Board determines that the organization is non-responsive and continues to cause a risk to the reliability of the interconnected power systems, the Board will seek to remedy the violation by requesting assistance from appropriate regulatory authorities in the United States and Canada.

Task Force:

Recommends that NERC inform the federal and state or provincial authorities of both countries of the final results of all enforcement proceedings, and make the results of such proceedings public.

C. Violations in August 14, 2003 Blackout

NERC:

The Compliance and Standards investigation team will issue a final report in March or April of 2004 of violations of NERC and regional standards that occurred on August 14. (Seven violations are noted in this report (pages 19-20), but additional violations may be identified by NERC.) Within three months of the issuance of the report, NERC is to develop recommendations to improve the compliance process.

Task Force:

Recommends that NERC make its recommendations available to appropriate U.S. federal and state authorities, to appropriate authorities in Canada, and to the public.

D. Compliance Audits

NERC:

Established plans for two types of audits, compliance audits and readiness audits. Compliance audits would determine whether the subject entity is in documented compliance with NERC standards, policies, etc. Readiness audits focus on whether the entity is functionally capable of meeting the terms of its reliability responsibilities. Under the terms approved by NERC's Board, the readiness audits to be completed by June 30, 2004, will be conducted using existing NERC rules, policies, standards, and NERC compliance templates. Requirements for control areas will be based on the existing NERC Control Area Certification Procedure, and updated as new criteria are approved.

Task Force:

Supports the NERC effort to verify that all entities are compliant with reliability standards. Effective compliance and auditing will require that the NERC standards be improved rapidly to make them clear, unambiguous, measurable, and consistent with the Functional Model.

E. Audit Standards and Composition of Audit Teams

NERC:

Under the terms approved by the Board, the regional councils are to have primary responsibility for conducting the compliance audits, under the oversight and direct participation of staff from the NERC Compliance Enforcement Program. FERC and other relevant regulatory agencies will be invited to participate in the audits, subject to the same confidentiality conditions as the other team members.

Task Force:

Recommends that each team should have some members who are electric reliability experts from outside the region in which the audit is occurring. Also, some team members should be from outside the electricity industry, i.e., individuals with experience in systems engineering and management, such as persons from the nuclear power industry, the U.S. Navy, the aerospace industry, air traffic control, or other relevant industries or government agencies. To improve the objectivity and consistency of investigation and performance, NERC-organized teams should conduct these compliance audits, using NERC criteria (with regional variations if more stringent), as opposed to the regional councils using regionally developed criteria.

F. Public Release of Compliance Audit Reports

Task Force:

Recommends that NERC require all compliance audit reports to be publicly posted, excluding portions pertaining to physical and cyber security according to predetermined criteria. Such reports should draw clear distinctions between serious and minor violations of reliability standards or related requirements.

18. Support and strengthen NERC's Reliability Readiness Audit Program.[25]

On February 10, 2004, the NERC Board of Trustees approved the establishment of a NERC program for periodic reviews of the reliability readiness of all reliability coordinators and control areas. The Task Force strongly supports this action, and recommends certain additional measures, as described below.

A. Readiness Audits

NERC:

In its directives of February 10, 2004, NERC indicated that it and the regional councils would jointly establish a program to audit the reliability readiness of all reliability coordinators and control areas within three years and continuing thereafter on a three-year cycle. Twenty audits of high-priority areas will be completed by June 30, 2004, with particular attention to deficiencies identified in the investigation of the August 14 blackout.

Task Force:

Recommends that the remainder of the first round of audits be completed within two years, as compared to NERC's plan for three years.

B. Public Release of Readiness Audit Reports

Task Force:

Recommends that NERC require all readiness audit reports to be publicly posted, excluding portions pertaining to physical and cyber security. Reports should also be sent directly to DOE, FERC, and relevant authorities in Canada and state commissions. Such reports should draw clear distinctions between serious and minor violations of reliability standards or related requirements.

19. Improve near-term and long-term training and certification requirements for operators, reliability coordinators, and operator support staff.[26]

In its requirements of February 10, 2004, NERC directed that all reliability coordinators, control areas, and transmission operators are to provide at least five days per year of training and drills in system emergencies, using realistic simulations, for each staff person with responsibility for the real-time operation or reliability monitoring of the bulk electric system. This system emergency training is in addition to other training requirements. Five days of system emergency training and drills are to be completed by June 30, 2004.

The Task Force supports these near-term requirements strongly. For the long term, the Task Force recommends that:

A. NERC should require training for the planning staff at control areas and reliability coordinators concerning power system characteristics

and load, VAr, and voltage limits, to enable them to develop rules for operating staff to follow.

B. NERC should require control areas and reliability coordinators to train grid operators, IT support personnel, and their supervisors to recognize and respond to abnormal automation system activity.

C. NERC should commission an advisory report by an independent panel to address a wide range of issues concerning reliability training programs and certification requirements.

The Task Force investigation team found that some reliability coordinators and control area operators had not received adequate training in recognizing and responding to system emergencies. Most notable was the lack of realistic simulations and drills to train and verify the capabilities of operating personnel. Such simulations are essential if operators and other staff are to be able to respond adequately to emergencies. This training deficiency contributed to the lack of situational awareness and failure to declare an emergency on August 14 while operator intervention was still possible (before events began to occur at a speed beyond human control).

Control rooms must remain functional under a wide range of possible conditions. Any person with access to a control room should be trained so that he or she understands the basic functions of the control room, and his or her role in relation to those of others in the room under any conditions. Information technology (IT) staff, in particular, should have a detailed understanding of the information needs of the system operators under alternative conditions.

The Task Force's cyber investigation team noted in its site visits an increasing reliance by control areas and utilities on automated systems to measure, report on, and change a wide variety of physical processes associated with utility operations.[27] If anything, this trend is likely to intensify in the future. These systems enable the achievement of major operational efficiencies, but their failure could cause or contribute to blackouts, as evidenced by the alarm failures at FirstEnergy and the state estimator deactivation at MISO.

Grid operators should be trained to recognize and respond more efficiently to security and automation problems, reinforced through the use of periodic exercises. Likewise, IT support personnel should be better trained to understand and respond to the requirements of grid operators during security and IT incidents.

NERC's near-term requirements for emergency preparedness training are described above. For the long term, training for system emergencies should be fully integrated into the broader training programs required for all system planners, system operators, their supervisors, and other control room support staff.

Advisory Report by Independent Panel on Industry Training Programs and Certification Requirements

Under the oversight of FERC and appropriate Canadian authorities, the Task Force recommends that NERC commission an independent advisory panel of experts to design and propose minimum training programs and certification procedures for the industry's control room managers and staff. This panel should be comprised of experts from electric industry organizations with outstanding training programs, universities, and other industries that operate large safety or reliability-oriented systems and training programs. (The Institute of Nuclear Power Operations (INPO), for example, provides training and other safety-related services to operators of U.S. nuclear power plants and plants in other countries.) The panel's report should provide guidance on issues such as:

1. Content of programs for new trainees
2. Content of programs for existing operators and other categories of employees
3. Content of continuing education programs and fraction of employee time to be committed to ongoing training
4. Going beyond paper-based, fact-oriented "knowledge" requirements for operators—i.e., confirming that an individual has the ability to cope with unforeseen situations and emergencies
5. In-house training vs. training by independent parties
6. Periodic accreditation of training programs
7. Who should certify trained staff?
8. Criteria to establish grades or levels of operator qualifications from entry level to supervisor or manager, based on education, training, and experience.

The panel's report should be delivered by March 31, 2005. FERC and Canadian authorities, in consultation with NERC and others, should evaluate the report and consider its findings in setting minimum training and certification requirements for control areas and reliability coordinators.

20. Establish clear definitions for *normal, alert* and *emergency* operational system conditions. Clarify roles, responsibilities, and authorities of reliability coordinators and control areas under each condition.[28]

NERC should develop by June 30, 2004 definitions for normal, alert, and emergency system conditions, and clarify reliability coordinator and control area functions, responsibilities, required capabilities, and required authorities under each operational system condition.

System operators need common definitions for normal, alert, and emergency conditions to enable them to act appropriately and predictably as system conditions change. On August 14, the principal entities involved in the blackout did not have a shared understanding of whether the grid was in an emergency condition, nor did they have a common understanding of the functions, responsibilities, capabilities, and authorities of reliability coordinators and control areas under emergency or near-emergency conditions.

NERC:

On February 10, 2004, NERC's Board of Trustees directed NERC's Operating Committee to "clarify reliability coordinator and control area functions, responsibilities, capabilities, and authorities" by June 30, 2004.

Task Force:

Recommends that NERC go further and develop clear definitions of three operating system conditions, along with clear statements of the roles and responsibilities of all participants, to ensure effective and timely actions in critical situations.

Designating three alternative system conditions (normal, alert, and emergency) would help grid managers to avert and deal with emergencies through preventive action. Many difficult situations are avoidable through strict adherence to sound procedures during normal operations. However, unanticipated difficulties short of an emergency still arise, and they must be addressed swiftly and skillfully to prevent them from becoming emergencies. Doing so requires a high level of situational awareness that is difficult to sustain indefinitely, so an intermediate "alert" state is needed, between "normal" and "emergency." In some areas (e.g., NPCC) an "alert" state has already been established.

21. Make more effective and wider use of system protection measures.[29]

In its requirements of February 10, 2004, NERC:

A. Directed all transmission owners to evaluate the settings of zone 3 relays on all transmission lines of 230 kV and higher.

B. Directed all regional councils to evaluate the feasibility and benefits of installing under-voltage load shedding capability in load centers.

C. Called for an evaluation within one year of its planning standard on system protection and control to take into account the lessons from the August 14 blackout.

The Task Force supports these actions strongly, and recommends certain additional measures, as described below.

A. Evaluation of Zone 3 Relays

NERC:

Industry is to review zone 3 relays on lines of 230 kV and higher.

Task Force:

Recommends that NERC broaden the review to include operationally significant 115 kV and 138 kV lines, e.g., lines that are part of monitored flowgates or interfaces. Transmission owners should also look for zone 2 relays set to operate like zone 3s.

B. Evaluation of Applicability of Under-Voltage Load Shedding

NERC:

Required each regional reliability council to evaluate the feasibility and benefits of under-voltage load shedding (UVLS) capability in load centers that could become unstable as a result of insufficient reactive power following credible multiple-contingency events. The regions should complete the initial studies and report the results to NERC within one year. The regions should promote the installation of under-voltage load shedding capabilities within critical areas where beneficial, as determined by the studies to be effective in preventing or containing an uncontrolled cascade of the power system.

Task Force:

Recommends that NERC require the results of the regional studies to be provided to federal and state or provincial regulators at the same time that they are reported to NERC. In addition, NERC should require every entity with a new or existing UVLS program to have a well-documented set of guidelines for operators that specify the conditions and triggers for UVLS use.

C. Evaluation of NERC's Planning Standard III

NERC:

Plans to evaluate Planning Standard III, System Protection and Control, and propose, by March 1, 2005, specific revisions to the criteria to address adequately the issue of slowing or limiting the propagation of a cascading failure, in light of the experience gained on August 14.

Task Force:

Recommends that NERC, as part of the review of Planning Standard III, determine the goals and principles needed to establish an integrated approach to relay protection for generators and transmission lines and the use of under-frequency and under-voltage load shedding (UFLS and UVLS) programs. An integrated approach is needed to ensure that at the local and regional level these interactive components provide an appropriate balance of risks and benefits in terms of protecting specific assets and facilitating overall grid survival. This review should take into account the evidence from August 14 of some unintended consequences of installing Zone 3 relays and using manufacturer-recommended settings for relays protecting generators. It should also include an assessment of the appropriate role and scope of UFLS and UVLS, and the appropriate use of time delays in relays.

Recommends that in this effort NERC should work with industry and government research organizations to assess the applicability of existing and new technology to make the interconnections less susceptible to cascading outages.

22. Evaluate and adopt better real-time tools for operators and reliability coordinators.[30]

NERC's requirements of February 10, 2004, direct its Operating Committee to evaluate within one year the real-time operating tools necessary for reliability operation and reliability coordination, including backup capabilities. The committee's report is to address both minimum acceptable capabilities for critical reliability functions and a guide to best practices.

The Task Force supports these requirements strongly. It recommends that NERC require the committee to:

A. Give particular attention in its report to the development of guidance to control areas and reliability coordinators on the use of automated wide-area situation visualization display systems and the integrity of data used in those systems.

B. Prepare its report in consultation with FERC, appropriate authorities in Canada, DOE, and the regional councils. The report should also inform actions by FERC and Canadian government agencies to establish minimum functional requirements for control area operators and reliability coordinators.

The Task Force also recommends that FERC, DHS, and appropriate authorities in Canada should require annual independent testing and certification of industry EMS and SCADA systems to ensure that they meet the minimum requirements envisioned in Recommendation 3.

A principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools and backup capabilities. In addition, the failure of FE's control computers and alarm system contributed directly to the lack of situational awareness. Likewise, MISO's incomplete tool set and the failure to supply its state estimator with correct system data on August 14 contributed to the lack of situational awareness. The need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations. Some wide-area tools to aid situational awareness (e.g., real-time phasor measurement systems) have been tested in some regions but are not yet in general use. Improvements in this area will require significant new investments involving existing or emerging technologies.

The investigation of the August 14 blackout revealed that there has been no consistent means across the Eastern Interconnection to provide an understanding of the status of the power grid outside of a control area. Improved visibility of the status of the grid beyond an operator's own area of control would aid the operator in making adjustments in its operations to mitigate potential problems. The expanded view advocated above would also enable facilities to be more proactive in operations and contingency planning.

Annual testing and certification by independent, qualified parties is needed because EMS and SCADA systems are the nerve centers of bulk electric networks. Ensuring that these systems are functioning properly is critical to sound and reliable operation of the networks.

23. Strengthen reactive power and voltage control practices in all NERC regions.[31]

NERC's requirements of February 10, 2004 call for a reevaluation within one year of existing reactive power and voltage control standards and how they are being implemented in the ten NERC regions. However, by June 30, 2004, ECAR is required to review its reactive power and voltage criteria and procedures, verify that its criteria and procedures are being fully implemented in regional and member studies and operations, and report the results to the NERC Board.

The Task Force supports these requirements strongly. It recommends that NERC require the regional analyses to include recommendations for appropriate improvements in operations or facilities, and to be subject to rigorous peer review by experts from within and outside the affected areas.

The Task Force also recommends that FERC and appropriate authorities in Canada require all tariffs or contracts for the sale of generation to include provisions specifying that the generators can be called upon to provide or increase reactive power output if needed for reliability purposes, and that the generators will be paid for any lost revenues associated with a reduction of real power sales attributable to a required increase in the production of reactive power.

Reactive power problems were a significant factor in the August 14 outage, and they were also important elements in several of the earlier outages detailed in Chapter 7.[32] Accordingly, the Task Force agrees that a comprehensive review is needed of North American practices with respect to managing reactive power requirements and maintaining an appropriate balance among alternative types of reactive resources.

Regional Analyses, Peer Reviews, and Follow-Up Actions

The Task Force recommends that each regional reliability council, working with reliability coordinators and the control areas serving major load centers, should conduct a rigorous reliability and adequacy analysis comparable to that outlined in FERC's December 24, 2003, Order[33] to FirstEnergy concerning the Cleveland-Akron area. The Task Force recommends that NERC develop a prioritized list for which areas and loads need this type of analysis and a schedule that ensures that the analysis will be completed for all such load centers by December 31, 2005.

24. Improve quality of system modeling data and data exchange practices.[34]

NERC's requirements of February 10, 2004 direct that within one year the regional councils are to establish and begin implementing criteria and procedures for validating data used in power flow models and dynamic simulations by benchmarking model data with actual system performance. Validated modeling data shall be exchanged on an inter-regional basis as needed for reliable system planning and operation.

The Task Force supports these requirements strongly. The Task Force also recommends that FERC and appropriate authorities in Canada require all generators, regardless of ownership, to collect and submit generator data to NERC, using a regulator-approved template.

The after-the-fact models developed to simulate August 14 conditions and events found that the dynamic modeling assumptions for generator and load power factors in regional planning and operating models were frequently inaccurate. In particular, the assumptions of load power factor were overly optimistic—loads were absorbing much more reactive power than the pre-August 14 models indicated. Another suspected problem concerns modeling of shunt capacitors under depressed voltage conditions.

NERC should work with the regional reliability councils to establish regional power system models that enable the sharing of consistent and validated data among entities in the region. Power flow and transient stability simulations should be periodically benchmarked with actual system events to validate model data. Viable load (including load power factor) and generator testing programs are necessary to improve agreement between power flows and dynamic simulations and the actual system performance.

During the data collection phase of the blackout investigation, when control areas were asked for information pertaining to merchant generation within their area, the requested data was frequently not available because the control area had not recorded the status or output of the generator at a given point in time. Some control area operators also asserted that some of the data that did exist was commercially sensitive or confidential. To correct such problems, the Task Force recommends that FERC and authorities in Canada require all generators, regardless of ownership, to collect and submit generator data, according to a regulator-approved template.

25. NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards.[35]

The Task Force recommends that, with support from FERC and appropriate authorities in Canada, NERC should:

A. Re-examine its existing body of standards, guidelines, etc., to identify those that are most important and ensure that all concerns that merit standards are addressed in the plan for standards development.

B. Re-examine the plan to ensure that those that are the most important or the most out-of-date are addressed early in the process.

C. Build on existing provisions and focus on what needs improvement, and incorporate compliance and readiness considerations into the drafting process.

D. Re-examine the Standards Authorization Request process to determine whether, for each standard, a review and modification of an existing standard would be more efficient than development of wholly new text for the standard.

NERC has already begun a long-term, systematic process to reevaluate its standards. It is of the greatest importance, however, that this process not dilute the content of the existing standards, nor conflict with the right of regions or other areas to impose more stringent standards. The state of New York, for example, operates under mandatory and more stringent reliability rules and standards than those required by NERC and NPCC.[36]

Similarly, several commenters on the Interim Report wrote jointly that:

> *NERC standards are the minimum—national standards should always be minimum rather than absolute or "one size fits all" criteria. [Systems for] densely populated areas, like the metropolitan areas of New York, Chicago, or Washington, must be designed and operated in accordance with a higher level of reliability than would be appropriate for sparsely populated parts of the country. It is essential that regional differences in terms of load and population density be recognized in the application of planning and operating criteria. Any move to adopt a national, "one size fits all" formula for all parts of the United States would be disastrous to reliability . . . .*
>
> *A strong transmission system designed and operated in accordance with weakened criteria would be disastrous. Instead, a concerted effort should be undertaken to determine if existing reliability criteria should be strengthened. Such an effort would recognize the geo-electrical magnitude of today's interconnected networks, and the increased complexities deregulation and restructuring have introduced in planning and operating North American power systems. Most important, reliability should be considered a higher priority than commercial use. Only through strong standards and careful engineering can unacceptable power failures like the August 14 blackout be avoided in the future.*[37]

26. Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate.[38]

NERC should work with reliability coordinators and control area operators to improve the effectiveness of internal and external communications during alerts, emergencies, or other critical situations, and ensure that all key parties, including state and local officials, receive timely and accurate information. NERC should task the regional councils to work together to develop communications protocols by December 31, 2004, and to assess and report on the adequacy of emergency communications systems within their regions against the protocols by that date.

On August 14, 2003, reliability coordinator and control area communications regarding conditions in northeastern Ohio were in some cases ineffective, unprofessional, and confusing. Ineffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade. Consistent application of effective communications protocols, particularly during alerts and emergencies, is essential to reliability. Standing hotline networks, or a functional equivalent, should be established for use in alerts and emergencies (as opposed to one-on-one phone calls) to ensure that all key parties are able to give and receive timely and accurate information.

27. Develop enforceable standards for transmission line ratings.[39]

NERC should develop clear, unambiguous requirements for the calculation of transmission line ratings (including dynamic ratings), and require that all lines of 115 kV or higher be rerated according to these requirements by June 30, 2005.

As seen on August 14, inadequate vegetation management can lead to the loss of transmission lines that are not overloaded, at least not according to their rated limits. The investigation of the blackout, however, also found that even after allowing for regional or geographic differences, there is still significant variation in how the ratings of existing lines have been calculated. This variation—in terms of assumed ambient temperatures, wind speeds, conductor strength, and the purposes and duration of normal, seasonal, and emergency ratings—makes the ratings themselves unclear, inconsistent, and unreliable across a region or between regions. This situation creates unnecessary and unacceptable uncertainties about the safe carrying capacity of individual lines on the transmission networks. Further, the appropriate use of dynamic line ratings needs to be included in this review because adjusting a line's rating according to changes in ambient conditions may enable the line to carry a larger load while still meeting safety requirements.

28. Require use of time-synchronized data recorders.[40]

In its requirements of February 10, 2004, NERC directed the regional councils to define within one year regional criteria for the application of synchronized recording devices in key power plants and substations.

The Task Force supports the intent of this requirement strongly, but it recommends a broader approach:

A. FERC and appropriate authorities in Canada should require the use of data recorders synchronized by signals from the Global Positioning System (GPS) on all categories of facilities whose data may be needed to investigate future system disturbances, outages, or blackouts.

B. NERC, reliability coordinators, control areas, and transmission owners should determine where high speed power system disturbance recorders are needed on the system, and ensure that they are installed by December 31, 2004.

C. NERC should establish data recording protocols.

D. FERC and appropriate authorities in Canada should ensure that the investments called for in this recommendation will be recoverable through transmission rates.

A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. The Task Force's investigators labored over thousands of data items to determine the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly faster and easier if there had been wider use of synchronized data recording devices.

NERC Planning Standard I.F, Disturbance Monitoring, requires the use of recording devices for disturbance analysis. On August 14, time recorders were frequently used but not synchronized to a time standard. Today, at a relatively modest cost, all digital fault recorders, digital event recorders, and power system disturbance recorders can and should be time-stamped at the point of observation using a Global Positioning System (GPS) synchronizing signal. (The GPS signals are synchronized with the atomic clock maintained in Boulder, Colorado by the U.S. National Institute of Standards and Technology.) Recording and time-synchronization equipment should be monitored and calibrated to assure accuracy and reliability.

It is also important that data from automation systems be retained at least for some minimum period, so that if necessary it can be archived to enable adequate analysis of events of particular interest.

29. Evaluate and disseminate lessons learned during system restoration.[41]

In the requirements it issued on February 10, 2004, NERC directed its Planning Committee to work with the Operating Committee, NPCC, ECAR, and PJM to evaluate the black start and system restoration performance following the outage of August 14, and to report within one year the results of that evaluation, with recommendations for

improvement. Within six months of the Planning Committee's report, all regional councils are to have reevaluated their plans and procedures to ensure an effective black start and restoration capability within their region.

The Task Force supports these requirements strongly. In addition, the Task Force recommends that NERC should require the Planning Committee's review to include consultation with appropriate stakeholder organizations in all areas that were blacked out on August 14.

The efforts to restore the power system and customer service following the outage were generally effective, considering the massive amount of load lost and the large number of generators and transmission lines that tripped. Fortunately, the restoration was aided by the ability to energize transmission from neighboring systems, thereby speeding the recovery.

Despite the apparent success of the restoration effort, it is important to evaluate the results in more detail to compare them with previous blackout/restoration studies and determine opportunities for improvement. Black start and restoration plans are often developed through study of simulated conditions. Robust testing of live systems is difficult because of the risk of disturbing the system or interrupting customers. The August 14 blackout provides a valuable opportunity to review actual events and experiences to learn how to better prepare for system black start and restoration in the future. That opportunity should not be lost.

30. Clarify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages.[42]

NERC should work with the control areas and reliability coordinators to clarify the criteria for identifying critical facilities whose operational status can affect the reliability of neighboring areas, and to improve mechanisms for sharing information about unplanned outages of such facilities in near real-time.

The lack of accurate, near real-time information about unplanned outages degraded the performance of state estimator and reliability assessment functions on August 14. NERC and the industry must improve the mechanisms for sharing outage information in the operating time horizon (e.g., 15 minutes or less), to ensure the accurate and timely sharing of outage data needed by real-time operating tools such as state estimators, real-time contingency analyzers, and other system monitoring tools.

Further, NERC's present operating policies do not specify adequately criteria for identifying those critical facilities within reliability coordinator and control area footprints whose operating status could affect the reliability of neighboring systems. This leads to uncertainty about which facilities should be monitored by both the reliability coordinator for the region in which the facility is located and by one or more neighboring reliability coordinators.

31. Clarify that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit. Streamline the TLR process.[43]

NERC should clarify that the TLR procedure is often too slow for use in situations in which an affected system is already in violation of an Operating Security Limit. NERC should also evaluate experience to date with the TLR procedure and propose by September 1, 2004, ways to make it less cumbersome.

The reviews of control area and reliability coordinator transcripts from August 14 confirm that the TLR process is cumbersome, perhaps unnecessarily so, and not fast and predictable enough for use situations in which an Operating Security Limit is close to or actually being violated. NERC should develop an alternative to TLRs that can be used quickly to address alert and emergency conditions.

Group III. Physical and Cyber Security of North American Bulk Power Systems

32. Implement NERC IT standards.

The Task Force recommends that NERC standards related to physical and cyber security should be understood as being included within the body of standards to be made mandatory and enforceable in Recommendation No. 1. Further:

A. NERC should ensure that the industry has implemented its Urgent Action Standard 1200; finalize, implement, and ensure membership compliance with its Reliability Standard 1300 for Cyber Security and take actions to better communicate and enforce these standards.

B. CAs and RCs should implement existing and emerging NERC standards, develop and implement best practices and policies for IT and

security management, and authenticate and authorize controls that address EMS automation system ownership and boundaries.

Interviews and analyses conducted by the SWG indicate that within some of the companies interviewed there are potential opportunities for cyber system compromise of EMS and their supporting IT infrastructure. Indications of procedural and technical IT management vulnerabilities were observed in some facilities, such as unnecessary software services not denied by default, loosely controlled system access and perimeter control, poor patch and configuration management, and poor system security documentation.

An analysis of the more prevalent policies and standards within the electricity sector revealed that there is existing and expanding guidance on standards within the sector to perform IT and information security management.[44] NERC issued a temporary standard (Urgent Action Standard 1200, Cyber Security) on August 13, 2003, and is developing the formal Reliability Standard 1300 for Cyber Security. Both start the industry down the correct path, but there is a need to communicate and enforce these standards by providing the industry with recommended implementation guidance. Implementation guidance regarding these sector-wide standards is especially important given that implementation procedures may differ among CAs and RCs.

In order to address the finding described above, the Task Force recommends:

- NERC:
  - ➢ Ensure that the industry has implemented its Urgent Action Standard 1200 and determine if the guidance contained therein needs to be strengthened or amended in the ongoing development of its Reliability Standard 1300 for Cyber Security.
  - ➢ Finalize, implement, and ensure membership compliance of its Reliability Standard 1300 for Cyber Security and take actions to better communicate and enforce these standards. These actions should include, but not necessarily be limited to:
    1. The provision of policy, process, and implementation guidance to CAs and RCs; and
    2. The establishment of mechanisms for compliance, audit, and enforcement. This may include recommendations, guidance, or agreements between NERC, CAs and RCs that cover self-certification, self-assessment, and/or third-party audit.
  - ➢ Work with federal, state, and provincial/territorial jurisdictional departments and agencies to regularly update private and public sector standards, policies, and other guidance.
- CAs and RCs:
  - ➢ Implement existing and emerging NERC standards.
  - ➢ Develop and implement best practices and policies for IT and security management drawing from existing NERC and government authorities' best practices.[45] These should include, but not necessarily be limited to:
    1. Policies requiring that automation system products be delivered and installed with unnecessary services deactivated in order to improve "out-of-the-box security."
    2. The creation of centralized system administration authority within each CA and RC to manage access and permissions for automation access (including vendor management backdoors, links to other automation systems, and administrative connections).
  - ➢ Authenticate and authorize controls that address EMS automation system ownership and boundaries, and ensure access is granted only to users who have corresponding job responsibilities.

33. Develop and deploy IT management procedures.

CAs' and RCs' IT and EMS support personnel should develop procedures for the development, testing, configuration, and implementation of technology related to EMS automation systems and also define and communicate information security and performance requirements to vendors on a continuing basis. Vendors should ensure that system upgrades, service packs, and bug fixes are made available to grid operators in a timely manner.

Interviews and analyses conducted by the SWG indicate that, in some instances, there were ill-defined and/or undefined procedures for EMS automation systems software and hardware development, testing, deployment, and backup. In addition, there were specific instances of failures to perform system upgrade, version control, maintenance, rollback, and patch management tasks.

At one CA, these procedural vulnerabilities were compounded by inadequate, out-of-date, or nonexisting maintenance contracts with EMS vendors and contractors. This could lead to situations where grid operators could alter EMS components without vendor notification or authorization as well as scenarios in which grid operators are not aware of or choose not to implement vendor-recommended patches and upgrades.

34. Develop corporate-level IT security governance and strategies.

CAs and RCs and other grid-related organizations should have a planned and documented security strategy, governance model, and architecture for EMS automation systems.

Interviews and analysis conducted by the SWG indicate that in some organizations there is evidence of an inadequate security policy, governance model, strategy, or architecture for EMS automation systems. This is especially apparent with legacy EMS automation systems that were originally designed to be stand-alone systems but that are now interconnected with internal (corporate) and external (vendors, Open Access Same Time Information Systems (OASIS), RCs, Internet, etc.) networks. It should be noted that in some of the organizations interviewed this was not the case and in fact they appeared to excel in the areas of security policy, governance, strategy, and architecture.

In order to address the finding described above, the Task Force recommends that CAs, RCs, and other grid-related organizations have a planned and documented security strategy, governance model, and architecture for EMS automation systems covering items such as network design, system design, security devices, access and authentication controls, and integrity management as well as backup, recovery, and contingency mechanisms.

35. Implement controls to manage system health, network monitoring, and incident management.

IT and EMS support personnel should implement technical controls to detect, respond to, and recover from system and network problems. Grid operators, dispatchers, and IT and EMS support personnel should be provided the tools and training to ensure that the health of IT systems is monitored and maintained.

Interviews and analysis conducted by the SWG indicate that in some organizations there was ineffective monitoring and control over EMS-supporting IT infrastructure and overall IT network health. In these cases, both grid operators and IT support personnel did not have situational awareness of the health of the IT systems that provide grid information both globally and locally. This resulted in an inability to detect, assess, respond to, and recover from IT system-related cyber failures (failed hardware/software, malicious code, faulty configurations, etc.).

In order to address the finding described above, the Task Force recommends:

- IT and EMS support personnel implement technical controls to detect, respond to, and recover from system and network problems.
- Grid operators, dispatchers, and IT and EMS support personnel be provided with the tools and training to ensure that:
  - The health of IT systems is monitored and maintained.
  - These systems have the capability to be repaired and restored quickly, with a minimum loss of time and access to global and internal grid information.
  - Contingency and disaster recovery procedures exist and can serve to temporarily substitute for systems and communications failures during times when EMS automation system health is unknown or unreliable.
  - Adequate verbal communication protocols and procedures exist between operators and IT and EMS support personnel so that operators are aware of any IT-related problems that may be affecting their situational awareness of the power grid.

36. Initiate a U.S.-Canada risk management study.

In cooperation with the electricity sector, federal governments should strengthen and expand the scope of the existing risk management initiatives by undertaking a bilateral (Canada-U.S.) study of the vulnerabilities of shared electricity infrastructure and cross border interdependencies. Common threat and vulnerability assessment methodologies should be also developed, based on the work undertaken in the pilot phase of the current joint Canada-U.S. vulnerability assessment initiative, and their use promoted by CAs and RCs. To coincide with these initiatives, the electricity sector, in association with federal governments, should

develop policies and best practices for effective risk management and risk mitigation.

Effective risk management is a key element in assuring the reliability of our critical infrastructures. It is widely recognized that the increased reliance on IT by critical infrastructure sectors, including the energy sector, has increased the vulnerability of these systems to disruption via cyber means. The breadth of the August 14, 2003, power outage illustrates the vulnerabilities and interdependencies inherent in our electricity infrastructure.

Canada and the United States, recognizing the importance of assessing the vulnerabilities of shared energy systems, included a provision to address this issue in the Smart Border Declaration,[46] signed on December 12, 2001. Both countries committed, pursuant to Action Item 21 of the Declaration, to "conduct bi-national threat assessments on trans-border infrastructure and identify necessary protection measures, and initiate assessments for transportation networks and other critical infrastructure." These joint assessments will serve to identify critical vulnerabilities, strengths and weaknesses while promoting the sharing and transfer of knowledge and technology to the energy sector for self-assessment purposes.

A team of Canadian and American technical experts, using methodology developed by the Argonne National Laboratory in Chicago, Illinois, began conducting the pilot phase of this work in January 2004. The work involves a series of joint Canada-U.S. assessments of selected shared critical energy infrastructure along the Canada-U.S. border, including the electrical transmission lines and dams at Niagara Falls - Ontario and New York. The pilot phase will be completed by March 31, 2004.

The findings of the ESWG and SWG suggest that among the companies directly involved in the power outage, vulnerabilities and interdependencies of the electric system were not well understood and thus effective risk management was inadequate. In some cases, risk assessments did not exist or were inadequate to support risk management and risk mitigation plans.

In order to address these findings, the Task Force recommends:

- In cooperation with the electricity sector, federal governments should strengthen and expand the scope of the existing initiatives described above by undertaking a bilateral (Canada-U.S.) study of the vulnerabilities of shared electricity infrastructure and cross border interdependencies. The study should encompass cyber, physical, and personnel security processes and include mitigation and best practices, identifying areas that would benefit from further standardization.
- Common threat and vulnerability assessment methodologies should be developed, based on the work undertaken in the pilot phase of the current joint Canada-U.S. vulnerability assessment initiative, and their use promoted by CAs and RCs.
- The electricity sector, in association with federal governments, should develop policies and best practices for effective risk management and risk mitigation.

37. Improve IT forensic and diagnostic capabilities.

CAs and RCs should seek to improve internal forensic and diagnostic capabilities, ensure that IT support personnel who support EMS automation systems are familiar with the systems' design and implementation, and make certain that IT support personnel who support EMS automation systems have are trained in using appropriate tools for diagnostic and forensic analysis and remediation.

Interviews and analyses conducted by the SWG indicate that, in some cases, IT support personnel who are responsible for EMS automation systems are unable to perform forensic and diagnostic routines on those systems. This appears to stem from a lack of tools, documentation and technical skills. It should be noted that some of the organizations interviewed excelled in this area but that overall performance was lacking.

In order to address the finding described above, the Task Force recommends:

- CAs and RCs seek to improve internal forensic and diagnostic capabilities as well as strengthen coordination with external EMS vendors and contractors who can assist in servicing EMS automation systems;
- CAs and RCs ensure that IT support personnel who support EMS automation systems are familiar with the systems' design and implementation; and
- CAs and RCs ensure that IT support personnel who support EMS automation systems have access to and are trained in using appropriate

tools for diagnostic and forensic analysis and remediation.

38. Assess IT risk and vulnerability at scheduled intervals.

IT and EMS support personnel should perform regular risk and vulnerability assessment activities for automation systems (including EMS applications and underlying operating systems) to identify weaknesses, high-risk areas, and mitigating actions such as improvements in policy, procedure, and technology.

Interviews and analysis conducted by the SWG indicate that in some instances risk and vulnerability management were not being performed on EMS automation systems and their IT supporting infrastructure. To some CAs, EMS automation systems were considered "black box"[47] technologies; and this categorization removed them from the list of systems identified for risk and vulnerability assessment.

39. Develop capability to detect wireless and remote wireline intrusion and surveillance.

Both the private and public sector should promote the development of the capability of all CAs and RCs to reasonably detect intrusion and surveillance of wireless and remote wireline access points and transmissions. CAs and RCs should also conduct periodic reviews to ensure that their user base is in compliance with existing wireless and remote wireline access rules and policies.

Interviews conducted by the SWG indicate that most of the organizations interviewed had some type of wireless and remote wireline intrusion and surveillance detection protocol as a standard security policy; however, there is a need to improve and strengthen current capabilities regarding wireless and remote wireline intrusion and surveillance detection. The successful detection and monitoring of wireless and remote wireline access points and transmissions are critical to securing grid operations from a cyber security perspective.

There is also evidence that although many of the organizations interviewed had strict policies against allowing wireless network access, periodic reviews to ensure compliance with these policies were not undertaken.

40. Control access to operationally sensitive equipment.

RCs and CAs should implement stringent policies and procedures to control access to sensitive equipment and/or work areas.

Interviews conducted by the SWG indicate that at some CAs and RCs operationally sensitive computer equipment was accessible to non-essential personnel. Although most of these non-essential personnel were escorted through sensitive areas, it was determined that this procedure was not always enforced as a matter of everyday operations.

In order to address the finding described above, the Task Force recommends:

- That RCs and CAs develop policies and procedures to control access to sensitive equipment and/or work areas to ensure that:
  - Access is strictly limited to employees or contractors who utilize said equipment as part of their job responsibilities.
  - Access for other staff who need access to sensitive areas and/or equipment but are not directly involved in their operation (such as cleaning staff and other administrative personnel) is strictly controlled (via escort) and monitored.

41. NERC should provide guidance on employee background checks.

NERC should provide guidance on the implementation of its recommended standards on background checks, and CAs and RCs should review their policies regarding background checks to ensure they are adequate.

Interviews conducted with sector participants revealed instances in which certain company contract personnel did not have to undergo background check(s) as stringent as those performed on regular employees of a CA or RC. NERC Urgent Action Standard Section 1207 Paragraph 2.3 specifies steps to remediate sector weaknesses in this area but there is a need to communicate and enforce this standard by providing the industry with recommended implementation guidance, which may differ among CAs and RCs.

In order to address the finding described above, the Task Force recommends:

- NERC provide guidance on the implementation of its recommended standards on background checks, especially as they relate to the screening of contracted and sub-contracted personnel.
- CAs and RCs review their policies regarding background checks to ensure they are adequate before allowing sub-contractor personnel to access their facilities.

42. Confirm NERC ES-ISAC as the central point for sharing security information and analysis.

The NERC ES-ISAC should be confirmed as the central electricity sector point of contact for security incident reporting and analysis. Policies and protocols for cyber and physical incident reporting should be further developed including a mechanism for monitoring compliance. There also should be uniform standards for the reporting and sharing of physical and cyber security incident information across both the private and public sectors.

There are currently both private and public sector information sharing and analysis initiatives in place to address the reporting of physical and cyber security incidents within the electricity sector. In the private sector, NERC operates an Electricity Sector Information Sharing and Analysis Center (ES-ISAC) specifically to address this issue. On behalf of the U.S. Government, the Department of Homeland Security (DHS) operates the Information Analysis and Infrastructure Protection (IAIP) Directorate to collect, process, and act upon information on possible cyber and physical security threats and vulnerabilities. In Canada, Public Safety and Emergency Preparedness Canada has a 24/7 operations center for the reporting of incidents involving or impacting critical infrastructure. As well, both in Canada and the U.S., incidents of a criminal nature can be reported to law enforcement authorities of jurisdiction.

Despite these private and public physical and cyber security information sharing and analysis initiatives, an analysis of policies and procedures within the electricity sector reveals that reporting of security incidents to internal corporate security, law enforcement, or government agencies was uneven across the sector. The fact that these existing channels for incident reporting—whether security- or electricity systems-related—are currently underutilized is an operating deficiency which could hamper the industry's ability to address future problems in the electricity sector.

Interviews and analysis conducted by the SWG further indicate an absence of coherent and effective mechanisms for the private sector to share information related to critical infrastructure with government. There was also a lack of confidence on the part of private sector infrastructure owners and grid operators that information shared with governments could be protected from disclosure under Canada's Access to Information Act (ATIA) and the U.S. Freedom of Information Act (FOIA). On the U.S. side of the border, however, the imminent implementation of the Critical Infrastructure Information (CII) Act of 2002 should mitigate almost all industry concerns about FOIA disclosure. In Canada, Public Safety and Emergency Preparedness Canada relies on a range of mechanisms to protect the sensitive information related to critical infrastructure that it receives from its private sector stakeholders, including the exemptions for third party information that currently exist in the ATIA and other instruments. At the same time, Public Safety and Emergency Preparedness Canada is reviewing options for stronger protection of CI information, including potential changes in legislation.

In order to address the finding described above, the Task Force recommends:

- Confirmation of the NERC ES-ISAC as the central electricity sector point of contact for security incident reporting and analysis.
- Further development of NERC policies and protocols for cyber and physical incident reporting including a mechanism for monitoring compliance.
- The establishment of uniform standards for the reporting of physical and cyber security incidents to internal corporate security, private sector sector-specific information sharing and analysis bodies (including ISACs), law enforcement, and government agencies.
- The further development of new mechanisms and the promulgation of existing[48] Canadian and U.S. mechanisms to facilitate the sharing of electricity sector threat and vulnerability information across governments as well as between the private sector and governments.
- Federal, state, and provincial/territorial governments work to further develop and promulgate measures and procedures that protect critical, but sensitive, critical infrastructure-related information from disclosure.

43. Establish clear authority for physical and cyber security.

The task force recommends that corporations establish clear authority and ownership for physical and cyber security. This authority should have the ability to influence corporate decision-making and the authority to make physical and cyber security-related decisions.

Interviews and analysis conducted by the SWG indicate that some power entities did not implement best practices when organizing their security staff. It was noted at several entities that the Information System (IS) security staff reported to IT support personnel such as the Chief Information Officer (CIO).

Best practices across the IT industry, including most large automated businesses, indicate that the best way to balance security requirements properly with the IT and operational requirements of a company is to place security at a comparable level within the organizational structure. By allowing the security staff a certain level of autonomy, management can properly balance the associated risks and operational requirements of the facility.

44. Develop procedures to prevent or mitigate inappropriate disclosure of information.

The private and public sectors should jointly develop and implement security procedures and awareness training in order to mitigate or prevent disclosure of information by the practices of open source collection, elicitation, or surveillance.

SWG interviews and intelligence analysis provide no evidence of the use of open source collection, elicitation or surveillance against CAs or RCs leading up to the August 14, 2003, power outage. However, such activities may be used by malicious individuals, groups, or nation states engaged in intelligence collection in order to gain insights or proprietary information on electric power system functions and capabilities. Open source collection is difficult to detect and thus is best countered through careful consideration by industry stakeholders of the extent and nature of publicly-available information. Methods of elicitation and surveillance, by comparison, are more detectable activities and may be addressed through increased awareness and security training. In addition to prevention and detection, it is equally important that suspected or actual incidents of these intelligence collection activities be reported to government authorities.

In order to address the findings described above, the Task Force recommends:

- The private and public sectors jointly develop and implement security procedures and awareness training in order to mitigate disclosure of information not suitable for the public domain and/or removal of previously available information in the public domain (web sites, message boards, industry publications, etc.).
- The private and public sector jointly develop and implement security procedures and awareness training in order to mitigate or prevent disclosure of information by the practices of elicitation.
- The private and public sector jointly develop and implement security procedures and awareness training in order to mitigate, prevent, and detect incidents of surveillance.
- Where no mechanism currently exists, the private and public sector jointly establish a secure reporting chain and protocol for use of the information for suspected and known attempts and incidents of elicitation and surveillance.

Group IV. Canadian Nuclear Power Sector

The U.S. nuclear power plants affected by the August 14 blackout performed as designed. After reviewing the design criteria and the response of the plants, the U.S. members of the Nuclear Working Group had no recommendations relative to the U.S. nuclear power plants.

As discussed in Chapter 8, Canadian nuclear power plants did not trigger the power system outage or contribute to its spread. Rather, they disconnected from the grid as designed. The Canadian members of the Nuclear Working Group have, therefore, no specific recommendations with respect to the design or operation of Canadian nuclear plants that would improve the reliability of the Ontario electricity grid. The Canadian Nuclear Working Group, however, made two recommendations to improve the response to future events involving the loss of off-site power, one concerning backup electrical generation equipment to the CNSC's Emergency Operations Centre and another concerning the use of adjuster rods during future events involving the loss of off-site power. The Task Force accepted these recommendations, which are presented below.

45. The Task Force recommends that the Canadian Nuclear Safety Commission request Ontario Power Generation and Bruce Power to review operating procedures and operator training associated with the use of adjuster rods.

OPG and Bruce Power should review their operating procedures to see whether alternative procedures could be put in place to carry out or reduce the number of system checks required before placing the adjuster rods into automatic mode. This review should include an assessment of any regulatory constraints placed on the use of the adjuster rods, to ensure that risks are being appropriately managed.

Current operating procedures require independent checks of a reactor's systems by the reactor operator and the control room supervisor before the reactor can be put in automatic mode to allow the reactors to operate at 60% power levels. Alternative procedures to allow reactors to run at 60% of power while waiting for the grid to be re-established may reduce other risks to the health and safety of Ontarians that arise from the loss of a key source of electricity. CNSC oversight and approval of any changes to operating procedures would ensure that health and safety, security, or the environment are not compromised. The CNSC would assess the outcome of the proposed review to ensure that health and safety, security, and the environment would not be compromised as a result of any proposed action.

46. The Task Force recommends that the Canadian Nuclear Safety Commission purchase and install backup generation equipment.

In order to ensure that the CNSC's Emergency Operations Center (EOC) is available and fully functional during an emergency situation requiring CNSC response, whether the emergency is nuclear-related or otherwise, and that staff needed to respond to the emergency can be accommodated safely, the CNSC should have backup electrical generation equipment of sufficient capacity to provide power to the EOC, telecommunications and Information Technology (IT) systems and accommodations for the CNSC staff needed to respond to an emergency.

The August 2003 power outage demonstrated that the CNSC's Emergency Operations Center, IT, and communications equipment are vulnerable if there is a loss of electricity to the Ottawa area.

Endnotes

[1] In fairness, it must be noted that reliability organizations in some areas have worked diligently to implement recommendations from earlier blackouts. According to the *Initial Report by the New York State Department of Public Service on the August 14, 2003 Blackout*, New York entities implemented all 100 of the recommendations issued after the New York City blackout of 1977.

[2] The need for a systematic recommitment to reliability by all affected organizations was supported in various ways by many commenters on the *Interim Report*, including Anthony J. Alexander, FirstEnergy; David Barrie, Hydro One Networks, Inc.; Joseph P. Carson, P.E.; Harrison Clark; F. J. Delea, J.A. Casazza, G.C. Loehr, and R. M. Malizewski, Power Engineers Seeking Truth; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; and Raymond K. Kershaw, International Transmission Company.

[3] See supporting comments expressed by Anthony J. Alexander, FirstEnergy; Deepak Divan, SoftSwitching Technologies; Pierre Guimond, Canadian Nuclear Association; Hans Konow, Canadian Electricity Association; Michael Penstone, Hydro One Networks, Inc.; and James K. Robinson, PPL.

[4] See "The Economic Impacts of the August 2003 Blackout," Electric Consumers Resource Council (ELCON), February 2, 2004.

[5] The need for action to make standards enforceable was supported by many commenters, including David Barrie, Hydro One Networks, Inc.; Carl Burrell, IMO Ontario; David Cook, North American Electric Reliability Council; Deepak Divan, SoftSwitching Technologies; Charles J. Durkin, Northeast Power Coordinating Council; David Goffin, Canadian Chemical Producers' Association; Raymond K. Kershaw, International Transmission Company; Hans Konow, Canadian Electricity Association; Barry Lawson, National Rural Electric Cooperative Association; William J. Museler, New York Independent System Operator; Eric B. Stephens, Ohio Consumers' Counsel; Gordon Van Welie, ISO New England, Inc.; and C. Dortch Wright, on behalf of James McGreevey, Governor of New Jersey.

[6] This recommendation was suggested by some members of the Electric System Working Group.

[7] The need to evaluate and where appropriate strengthen the institutional framework for reliability management was supported in various respects by many commenters, including Anthony J. Alexander, FirstEnergy Corporation; David Barrie, Hydro One Networks, Inc.; Chris Booth, Experienced Consultants LLC; Carl Burrell, IMO Ontario;Linda Campbell, Florida Reliability Coordinating Council; Linda Church Ciocci, National Hydropower Association; David Cook, NERC; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Charles J. Durkin, Northeast Power Coordinating Council; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Michael W. Golay, Massachusetts Institute of Technology; Leonard S. Hyman, Private Sector Advisors, Inc; Marija Ilic, Carnegie Mellon University; Jack Kerr, Dominion Virginia Power; Raymond K. Kershaw,

International Transmission Company; Paul Kleindorfer, University of Pennsylvania; Michael Kormos, PJM Interconnection; Bill Mittelstadt, Bonneville Power Administration; William J. Museler, New York Independent System Operator; James K. Robinson, PPL; Eric B. Stephens, Ohio Consumers' Counsel; John Synesiou, IMS Corporation; Gordon Van Welie, ISO New England; Vickie Van Zandt, Bonneville Power Administration; and C. Dortch Wright, on behalf of James McGreevey, Governor of New Jersey.

8 Several commenters noted the importance of clarifying that prudently incurred reliability expenses and investments will be recoverable through regulator-approved rates. These commenters include Anthony J. Alexander, FirstEnergy Corporation; Deepak Divan, SoftSwitching Technologies; Stephen Fairfax, MTechnology, Inc.; Michael W. Golay, Massachusetts Institute of Technology; Pierre Guimond, Canadian Nuclear Association; Raymond K. Kershaw, International Transmission Company; Paul R. Kleindorfer, University of Pennsylvania: Hans Konow, Canadian Electricity Association; Barry Lawson, National Rural Electric Cooperative Association; and Michael Penstone, Hydro One Networks, Inc.

9 The concept of an ongoing NERC process to track the implementation of existing and subsequent recommendations was initated by NERC and broadened by members of the Electric System Working Group. See comments by David Cook, North American Electric Reliability Council.

10 This recommendation was suggested by NERC and supported by members of the Electric System Working Group.

11 See comments by Jack Kerr, Dominion Virginia Power, and Margie Phillips, Pennsylvania Services Integration Consortium.

12 The concept of a "reliability impact consideration" was suggested by NERC and supported by the Electric System Working Group.

13 The suggestion that EIA should become a source of reliability data and information came from a member of the Electric System Working Group.

14 Several commenters raised the question of whether there was a linkage between the emergence of competition (or increased wholesale electricity trade) in electricity markets and the August 14 blackout. See comments by Anthony J. Alexander, FirstEnergy Corporation; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Brian O'Keefe, Canadian Union of Public Employees; Les Pereira; and John Wilson.

15 NIMBY: "Not In My Back Yard."

16 Several commenters either suggested that government agencies should expand their research in reliability-related topics, or emphasized the need for such R&D more generally. See comments by Deepak Divan, SoftSwitching Technologies; Marija Ilic, Carnegie Mellon University; Hans Konow, Canadian Electricity Association; Stephen Lee, Electric Power Research Institute; James K. Robinson, PPL; John Synesiou, IMS Corporation; and C. Dortch Wright on behalf of Governor James McGreevey of New Jersey.

17 The concept of a standing framework for grid-related investigations was initiated by members of the Electric System Working Group, after noting that the U.S. National Aeronautics and Space Administration (NASA) had created a similar arrangement after the *Challenger* explosion in 1986. This framework was put to use immediately after the loss of the shuttle *Columbia* in 2003.

18 This subject was addressed in detail in comments by David Cook, North American Electric Reliability Council; and in part by comments by Anthony J. Alexander, FirstEnergy Corporation; Ajay Garg, Hydro One Networks, Inc.; George Katsuras, IMO Ontario; and Vickie Van Zandt, Bonneville Power Administration.

19 U.S. Federal Energy Regulatory Commission, 105 FERC ¶ 61,372, December 24, 2003.

20 See ECAR website, http://www.ecar.org/documents/document%201_6-98.pdf.

21 See NERC website, http://www.nerc.com/standards/.

22 The need to ensure better maintenance of required electrical clearances in transmission right of way areas was emphasized by several commenters, including Richard E. Abbott, arborist; Anthony J. Alexander, FirstEnergy Corporation; David Barrie, Hydro One Networks, Inc.; David Cook, North American Electric Reliability Council; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Tadashi Mano, Tokyo Electric Power Company; Eric B. Stephens, Ohio Consumers' Counsel; Vickie Van Zandt, Bonneville Power Administration; and Donald Wightman, Utility Workers Union of America.

23 *Utility Vegetation Management Final Report*, CN Utility Consulting, LLC, March 2004, commissioned by the U.S. Federal Energy Regulatory Commission to support the investigation of the August 14, 2003 blackout.

24 The need to strengthen and verify compliance with NERC standards was noted by several commenters. See comments by David Barrie, Hydro One Networks, Inc.; Carl Burrell, IMO Ontario; David Cook, North American Electric Reliability Council; and Eric B. Stephens, Ohio Consumers' Counsel.

25 The need to verify application of NERC standards via readiness audits—before adverse incidents occur—was noted by several commenters. See comments by David Barrie, Hydro One Networks, Inc.; David Cook, North American Electric Reliability Council; Barry Lawson, National Rural Electric Cooperative Association; Bill Mittelstadt, Bonneville Power Administration; and Eric B. Stephens, Ohio Consumers' Counsel.

26 The need to improve the training and certification requirements for control room management and staff drew many comments. See comments by David Cook, North American Electric Reliability Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Victoria Doumtchenko, MPR Associates; Pat Duran, IMO Ontario; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; George Katsuras, IMO Ontario; Jack Kerr, Dominion Virginia Power; Tim Kucey, National Energy Board, Canada; Stephen Lee, Electric Power Research Institute; Steve Leovy, personal comment; Ed Schwerdt, Northeast Power Coordinating Council; Tapani O. Seppa, The Valley Group, Inc.; Eric B. Stephens, Ohio Consumers' Counsel; Vickie Van Zandt, Bonneville Power Company; Don Watkins, Bonneville Power Administration; and Donald Wightman, Utility Workers Union of America.

27 This reliance, and the risk of an undue dependence, is often unrecognized in the industry.

28 Many parties called for clearer statement of the roles, responsibilities, and authorities of control areas and reliability coordinators, particularly in emergency situations. See comments by Anthony J. Alexander, FirstEnergy Corporation; Chris Booth, Experienced Consultants LLC; Michael Calimano, New York ISO; Linda Campbell, Florida Reliability Coordinating Council; David Cook, North American Electric

Reliability Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Mark Fidrych, Western Area Power Authority; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Carl Hauser, Washington State University; Stephen Kellat; Jack Kerr, Dominion Virginia Power; Raymond K. Kershaw, International Transmission Company; Michael Kormos, PJM Interconnection; William J. Museler, New York Independent System Operator; Tapani O. Seppa, The Valley Group, Inc.; John Synesiou, IMS Corporation; Gordon Van Welie, ISO New England, Inc.; Vickie Van Zandt, Bonneville Power Administration; Kim Warren, IMO Ontario; and Tom Wiedman, Consolidated Edison. Members of the Electric System Working Group initiated the concept of defining an "alert" status, between "normal" and "emergency," and associated roles, responsibilities, and authorities.

[29] The need to make better use of system protection measures received substantial comment, including comments by James L. Blasiak, International Transmission Company; David Cook, North American Electric Reliability Council; Charles J. Durkin, Northeast Power Coordinating Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Gurgen and Spartak Hakobyan, personal study; Marija Ilic, Carnegie Mellon University; Shinichi Imai, Tokyo Electric Power Company; Jack Kerr, Dominion Virginia Power; Stephen Lee, Electric Power Research Institute; Ed Schwerdt, Northeast Power Coordinating Council; Robert Stewart, PG&E; Philip Tatro, National Grid Company; Carson Taylor, Bonneville Power Administration; Vickie Van Zandt, Bonneville Power Company; Don Watkins, Bonneville Power Administration; and Tom Wiedman, Consolidated Edison.

[30] The subject of developing and adopting better real-time tools for control room operators and reliability coordinators drew many comments, including those by Anthony J. Alexander, FirstEnergy Corporation; Eric Allen, New York ISO; Chris Booth, Experienced Consultants, LLC; Mike Calimano, New York ISO; Claudio Canizares, University of Waterloo (Ontario); David Cook, North American Electric Reliability Council; Deepak Divan, SoftSwitching Technologies Victoria Doumtchenko, MPR Associates; Pat Duran, IMO Ontario; Bill Eggertson, Canadian Association for Renewable Energies; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Jack Kerr, Dominion Virginia Power; Raymond K. Kershaw, International Transmission Company; Michael Kormos, PJM Interconnection; Tim Kucey, National Energy Board, Canada; Steve Lapp, Lapp Renewables; Stephen Lee, Electric Power Research Institute; Steve Leovy; Tom Levy; Peter Love, Canadian Energy Efficiency Alliance; Frank Macedo, Hydro One Networks, Inc.; Bill Mittelstadt, Bonneville Power Administration; Fiona Oliver, Canadian Energy Efficiency Alliance; Peter Ormund, Mohawk College; Don Ross, Prince Edward Island Wind Co-op Limited; James K. Robinson, PPL; Robert Stewart, PG&E; John Synesiou, IMS Corporation; Gordon Van Welie, ISO New England, Inc.; Vickie Van Zandt, Bonneville Power Administration; Don Watkins, Bonneville Power Administration; Chris Winter, Conservation Council of Ontario; David Zwergel, Midwest ISO. The concept of requiring annual testing and certification of operators' EMS and SCADA systems was initiated by a member of the Electric System Working Group. Also, see comments by John Synesiou, IMS Corporation.

[31] The need to strengthen reactive power and voltage control practices was the subject of several comments. See comments by Claudio Canizares, University of Waterloo (Ontario); David Cook, North American Electric Reliability Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Stephen Fairfax, MTechnology, Inc.; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Shinichi Imai and Toshihiko Furuya, Tokyo Electric Power Company; Marija Ilic, Carnegie Mellon University; Frank Macedo, Hydro One Networks, Inc.; and Tom Wiedman, Consolidated Edison. Several commenters addressed issues related to the production of reactive power by producers of power for sale in wholesale markets. See comments by Anthony J. Alexander, FirstEnergy Corporation; K.K. Das, PowerGrid Corporation of India, Limited; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Stephen Fairfax, MTechnology, Inc.; and Carson Taylor, Bonneville Power Administration.

[32] See pages 107-108.

[33] U.S. Federal Energy Regulatory Commission, 105 FERC ¶ 61,372, December 24, 2003.

[34] The need to improve the quality of system modeling data and data exchange practices received extensive comment. See comments from Michael Calimano, New York ISO; David Cook, North American Electric Reliability Council; Robert Cummings, North American Electric Reliability Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Mark Fidrych, Western Area Power Administration; Jack Kerr, Dominion Virginia Power; Raymond K. Kershaw, International Transmission Company; Frank Macedo, Hydro One Networks, Inc.; Vickie Van Zandt, Bonneville Power Administration; Don Watkins, Bonneville Power Administration; and David Zwergel, Midwest ISO.

[35] Several commenters addressed the subject of NERC's standards in various respects, including Anthony J. Alexander, FirstEnergy Corporation; Carl Burrell, IMO Ontario; David Cook, North American Electric Reliability Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Charles J. Durkin, Northeast Power Coordinating Council; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Jack Kerr, Dominion Virginia Power; James K. Robinson, PPL; Mayer Sasson, New York State Reliability Council; and Kim Warren, IMO Ontario.

[36] See *Initial Report by the New York State Department of Public Service on the August 14, 2003 Blackout* (2004), and comments by Mayer Sasson, New York State Reliability Council.

[37] F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, "The Need for Strong Planning and Operating Criteria to Assure a Reliable Bulk Power Supply System," January 29, 2004.

[38] The need to tighten communications protocols and improve communications systems was cited by several commenters. See comments by Anthony J. Alexander, FirstEnergy Corporation; David Barrie, Hydro One Networks, Inc.; Carl Burrell, IMO Ontario; Michael Calimano, New York ISO; David Cook, North American Electric Reliability Council; Mark Fidrych, Western Area Power Administration; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Jack Kerr, Dominion Virginia Power; William Museler, New York ISO; John Synesiou, IMS Corporation; Vickie Van Zandt, Bonneville Power Administration; Don Watkins, Bonneville Power Administration; Tom Wiedman, Consolidated Edison.

[39] See comments by Tapani O. Seppa, The Valley Group, Inc.

[40] Several commenters noted the need for more systematic use of time-synchronized data recorders. In particular, see David Cook, North American Electric Reliability Council; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; and Robert Stewart, PG&E.

[41] The importance of learning from the system restoration experience associated with the August 14 blackout was stressed by Linda Church Ciocci, National Hydropower Association; David Cook, North American Electric Reliability Council; Frank Delea; Bill Eggertson, Canadian Association for Renewable Energies; Stephen Lee, Electric Power Research Institute; and Kim Warren, IMO Ontario.

[42] The need to clarify the criteria for identifying critical facilities and improving dissemination of updated information about unplanned outages was cited by Anthony J. Alexander, FirstEnergy Corporation; and Raymond K. Kershaw, International Transmission Company.

[43] The need to streamline the TLR process and limit the use of it to non-urgent situations was discussed by several commenters, including Anthony J. Alexander, FirstEnergy Corporation; Carl Burrell, IMO Ontario; Jack Kerr, Dominion Virginia Power; Raymond K. Kershaw, International Transmission Company; and Ed Schwerdt, Northeast Power Coordinating Council.

[44] NERC Standards at www.nerc.com (Urgent Action Standard 1200, Cyber Security, Reliability Standard 1300, Cyber Security) and Joint DOE/PCIB standards guidance at www.ea.doe.gov/pdfs/21stepsbooklet.pdf ("21 Steps to Improve Cyber Security of SCADA Networks").

[45] For example: "21 Steps to Improve Cyber Security of SCADA Networks," http://www.ea.doe.gov/pdfs/21stepsbooklet.pdf.

[46] Canadian reference: http://www.dfait-maeci.gc.ca/anti-terrorism/actionplan-en.asp; U.S. reference: http://www.whitehouse.gov/news/releases/2001/12/20011212-6.html.

[47] A "black box" technology is any device, sometimes highly important, whose workings are not understood by or accessible to its user.

[48] DOE Form 417 is an example of an existing, but underutilized, private/public sector information sharing mechanism.

Appendix A

Members of the U.S.-Canada Power System Outage Task Force and Its Three Working Groups

Task Force Co-Chairs

Spencer Abraham, Secretary of the U.S. Department of Energy (USDOE)

R. John Efford, Canadian Minister of Natural Resources (current) and **Herb Dhaliwal** (August-December 2003)

Canadian Task Force Members

Linda J. Keen, President and CEO of the Canadian Nuclear Safety Commission

Anne McLellan, Deputy Prime Minister and Minister of Public Safety and Emergency Preparedness

John Manley, (previous) Deputy Prime Minister and Minister of Finance

Kenneth Vollman, Chairman of the National Energy Board

U.S. Task Force Members

Nils J. Diaz, Chairman of the Nuclear Regulatory Commission

Tom Ridge, Secretary of the U.S. Department of Homeland Security (DHS)

Pat Wood, III, Chairman of the Federal Energy Regulatory Commission (FERC)

Principals Managing the Working Groups

Jimmy Glotfelty, Director, Office of Electric Transmission and Distribution, USDOE

Dr. Nawal Kamel, Special Advisor to the Deputy Minister of Natural Resources Canada (NRCan)

Working Groups

Electric System Working Group

Co-Chairs

David Meyer, Senior Advisor, Office of Electric Transmission and Distribution, USDOE (U.S. Government)

Thomas Rusnov, Senior Advisor, Natural Resources Canada (Government of Canada)

Alison Silverstein, Senior Energy Policy Advisor to the Chairman, FERC (U.S. Government)

Canadian Members

David Barrie, Senior Vice President, Asset Management, Hydro One

David Burpee, Director, Renewable and Electrical Energy Division, NRCan (Government of Canada)

David McFadden, Chair, National Energy and Infrastructure Industry Group, Gowling, Lafleur, Henderson LLP (Ontario)

U.S. Members

Donald Downes, Public Utility Commission Chairman (Connecticut)

Joseph H. Eto, Staff Scientist, Ernest Orlando Lawrence Berkeley National Laboratory, Consortium for Electric Reliability Technology Solutions (CERTS)

Jeanne M. Fox, President, New Jersey Board of Pubic Utilities (New Jersey)

H. Kenneth Haase, Sr. Vice President, Transmission, New York Power Authority (New York)

J. Peter Lark, Chairman, Public Service Commission (Michigan)

Blaine Loper, Senior Engineer, Pennsylvania Public Utility Commission (Pennsylvania)

William McCarty, Chairman, Indiana Utility Regulatory Commission (Indiana)

David O'Brien, Vermont Public Service Department, Commissioner (Vermont)

David O'Connor, Commissioner, Division of Energy Resources, Office of Consumer Affairs and Business Regulation (Massachusetts)

Alan Schriber, Public Utility Commission Chairman (Ohio)

Gene Whitney, Policy Analyst, Office of Science and Technology Policy (U.S. Government)

Security Working Group

Co-Chairs

William J.S. Elliott, Assistant Secretary to the Cabinet, Security and Intelligence, Privy Council Office (Government of Canada)

Robert Liscouski, Assistant Secretary for Infrastructure, Department of Homeland Security (U.S. Government)

Canadian Members

Curt Allen, Director Corporate Security, Management Board Secretariat, Office of the Corporate Chief Information Officer, Government of Ontario

Gary Anderson, Chief, Counter-Intelligence-Global, Canadian Security Intelligence Service (Government of Canada)

Michael Devancy, Deputy Chief, Information Technology Security, Communications Security Establishment (Government of Canada)

James Harlick, Assistant Deputy Minister, Public Safety and Emergency Preparedness Canada (Government of Canada)

Peter MacAulay, Officer in Charge of Technological Crime Branch, Royal Canadian Mounted Police (Government of Canada)

Ralph Mahar, Chief, Technical Operations, Scientific and Technical Services, Canadian Security Intelligence Service (Government of Canada)

Dr. James Young, Commissioner of Public Security, Ontario Ministry of Public Safety and Security (Ontario)

U.S. Members

Sid Casperson, Director, Office of Counter Terrorism (New Jersey)

Vincent DeRosa, Deputy Commissioner, Director of Homeland Security, Department of Public Safety (Connecticut)

Harold M. Hendershot, Acting Section Chief, Computer Intrusion Section, Federal Bureau of Investigation (U.S. Government)

Kevin Kolevar, Chief of Staff to the Deputy Secretary of Energy, Department of Energy (U.S. Government)

Paul Kurtz, Special Assistant to the President and Senior Director for Critical Infrastructure Protection, Homeland Security Council (U.S. Government)

James McMahon, Senior Advisor (New York)

Colonel Michael C. McDaniel, Assistant Adjutant General for Homeland Security (Michigan)

John Overly, Executive Director, Division of Homeland Security (Ohio)

Andy Purdy, Deputy Director, National Cyber Security Division, Information Analysis and Infrastructure Protection Directorate, DHS

Kerry L. Sleeper, Commissioner, Public Safety (Vermont)

Arthur Stephens, Deputy Secretary for Information Technology, Office of Administration (Pennsylvania)

Steve Schmidt, Section Chief, Special Technologies and Applications, FBI

Richard Swensen, Under Secretary, Office of Public Safety and Homeland Security (Massachusetts)

Simon Szykman, Senior Policy Analyst, Office of Science and Technology Policy (U.S. Government)

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Nils Diaz, Chairman, Nuclear Regulatory Commission (U.S. Government)

Linda J. Keen, President and Chief Executive Officer, Canadian Nuclear Safety Commission (Government of Canada)

Canadian Members

James Blyth, Director General, Directorate of Power Regulation, Canadian Nuclear Safety Commission (Government of Canada)

Duncan Hawthorne, Chief Executive Officer, Bruce Power (Ontario)

Robert Morrison, Senior Advisor to the Deputy Minister, Natural Resources Canada (Government of Canada)

Ken Pereira, Vice President, Operations Branch, Canadian Nuclear Safety Commission (Government of Canada)

U.S. Members

David J. Allard, CHP, Director, Bureau of Radiation Protection Department of Environmental Protection (Pennsylvania)

Frederick F. Butler, Commissioner, New Jersey Board of Public Utilities (New Jersey)

Sam J. Collins, Deputy Executive Director for Reactor Programs, Nuclear Regulatory Commission

Paul Eddy, Power Systems Operations Specialist, Public Service Commission (New York)

J. Peter Lark, Chairman, Public Service Commission (Michigan)

William D. Magwood IV, Director, Office of Nuclear Energy, Science and Technology, Department of Energy (U.S. Government)

Dr. G. Ivan Moldonado, Associate Professor, Mechanical, Industrial and Nuclear Engineering; University of Cincinnati (Ohio)

David O'Brien, Commissioner, Department of Public Service (Vermont)

David O'Connor, Commissioner, Division of Energy Resources, Office of Consumer Affairs and Business Regulation (Massachusetts)

Gene Whitney, Policy Analyst, National Science and Technology Policy, Executive Office of the President (U.S. Government)

Edward Wilds, Bureau of Air Management, Department of Environmental Protection (Connecticut)

This report reflects tireless efforts by hundreds of individuals not identified by name above. They include electrical engineers, information technology experts, and other specialists from across the North American electricity industry, the academic world, regulatory agencies in the U.S. and Canada, the U.S. Department of Energy and its national laboratories, the U.S. Department of Homeland Security, the U.S. Federal Bureau of Investigation, Natural Resources Canada, the Royal Canadian Mounted Police, the Bonneville Power Administration, the Western Area Power Administration, the Tennessee Valley Authority, the North American Electric Reliability Council, PJM Interconnection, Inc., Ontario's Independent Market Operator, and many other organizations. The members of the U.S.-Canada Power System Outage Task Force thank these individuals, and congratulate them for their dedication and professionalism.

Appendix B

Description of Outage Investigation and Process for Development of Recommendations

On August 14, 2003, the northeastern U.S. and Ontario, Canada, suffered one of the largest power blackouts in the history of North America. The area affected extended from New York, Massachusetts, and New Jersey west to Michigan, and from Ohio north to Ontario, Canada.

President George W. Bush and Prime Minister Jean Chrétien created a U.S.-Canada Task Force to identify the causes of the power outage and to develop recommendations to prevent and contain future outages. U.S. Energy Secretary Spencer Abraham and Minister of Natural Resources Canada Herb Dhaliwal, meeting in Detroit, Michigan, on August 20, agreed on an outline for the activities of the Task Force.

This appendix outlines the process used for the determination of why the blackout occurred and was not contained and explains how recommendations were developed to prevent and minimize the scope of future outages. Phase I of the process was completed when the Interim Report, identifying what happened and why, was released on November 19, 2003. This Final Report, released on April 5, 2004, completes Phase II of the process by providing recommendations acceptable to both countries for preventing and reducing the scope of future blackouts. This report, which encompasses both the findings of the Interim Report and updated information from continued analysis by the investigative teams, totally supersedes the Interim Report.

During Phase II, the Task Force sought the views of the public and expert stakeholders in Canada and the U.S. towards the development of the final recommendations. People were asked to comment on the Interim Report and provide their views on recommendations to enhance the reliability of the electric system in each country. The Task Force collected this information by several methods, including public forums, workshops of technical experts, and electronic submissions to the NRCan and DOE web sites.

Verbatim transcripts of the forums and workshops were provided on-line, on both the NRCan and DOE web sites. In Canada, which operates in both English and French, comments were posted in the language in which they were submitted. Individuals who either commented on the Interim Report, provided suggestions for recommendations to improve reliability, or both are listed in Appendix C. Their input was greatly appreciated. Their comments can be viewed in full or in summary at http://www.nrcan.gc.ca or at http://www.electricity.doe.gov.

Task Force Composition and Responsibilities

The co-chairs of the Task Force were U.S. Secretary of Energy Spencer Abraham and Minister of Natural Resources Canada (NRCan) Herb Dhaliwal for Phase I and Minister of NRCan R. John Efford for Phase II. Other U.S. members were Nils J. Diaz, Chairman of the Nuclear Regulatory Commission, Tom Ridge, Secretary of Homeland Security, and Pat Wood III, Chairman of the Federal Energy Regulatory Commission. The other Canadian members were Deputy Prime Minister John Manley during Phase I and Anne McLellan, Deputy Prime Minister and Minister of Public Safety and Emergency Preparedness during Phase II, Linda J. Keen, President and CEO of the Canadian Nuclear Safety Commission, and Kenneth Vollman, Chairman of the National Energy Board. The coordinators for the Task Force were Jimmy Glotfelty on behalf of the U.S. Department of Energy and Dr. Nawal Kamel on behalf of Natural Resources Canada.

On August 27, 2003, Secretary Abraham and Minister Dhaliwal announced the formation of three Working Groups to support the work of the Task Force. The three Working Groups addressed electric system issues, security matters, and questions related to the performance of nuclear power plants over the course of the outage. The members of the Working Groups were officials from relevant federal departments and agencies, technical experts, and senior representatives from the affected states and the Province of Ontario.

U.S.-Canada-NERC Investigation Team

Under the oversight of the Task Force, three investigative teams of electric system, nuclear and cyber and security experts were established to investigate the causes of the outage. The electric system investigative team was comprised of individuals from several U.S. federal agencies, the U.S. Department of Energy's national laboratories, Canadian electric industry, Canada's National Energy Board, staff from the North American Electric Reliability Council (NERC), and the U.S. electricity industry. The overall investigative team was divided into several analytic groups with specific responsibilities, including data management, determining the sequence of outage events, system modeling, evaluation of operating tools and communications, transmission system performance, generator performance, NERC and regulatory standards/procedures and compliance, system planning and design studies, vegetation and right-of-way management, transmission and reliability investments, and root cause analysis.

Additional teams of experts were established to address issues related to the performance of nuclear power plants affected by the outage, and physical and cyber security issues related to the bulk power infrastructure. The security and nuclear investigative teams also had liaisons who worked closely with the various electric system investigative teams mentioned above.

Function of the Working Groups

The U.S. and Canadian co-chairs of each of the three Working Groups (i.e., an Electric System Working Group, a Nuclear Working Group, and a Security Working Group) designed investigative assignments to be completed by the investigative teams. These findings were synthesized into a single Interim Report reflecting the conclusions of the three investigative teams and the Working Groups. For Phase II, the Interim Report was enhanced with new information gathered from the technical conferences, additional modeling and analysis and public comments. Determination of when the Interim and Final Reports were complete and appropriate for release to the public was the responsibility of the U.S.-Canada Task Force and the investigation co-chairs.

Confidentiality of Data and Information

Given the seriousness of the blackout and the importance of averting or minimizing future blackouts, it was essential that the Task Force's teams have access to pertinent records and data from the regional transmission operators (RTOs) and independent system operators (ISOs) and electric companies affected by the blackout, and data from the nuclear and security associated entities. The investigative teams also interviewed appropriate individuals to learn what they saw and knew at key points in the evolution of the outage, what actions they took, and with what purpose. In recognition of the sensitivity of this information, Working Group members and members of the teams signed agreements affirming that they would maintain the confidentiality of data and information provided to them, and refrain from independent or premature statements to the media or the public about the activities, findings, or conclusions of the individual Working Groups or the Task Force as a whole.

After publication of the Interim Report, the Task Force investigative teams continued to evaluate the data collected during Phase I. Continuing with Phase I criteria, confidentiality was maintained in Phase II, and all investigators and working group members were asked to refrain from independent or premature statements to the media or the public about the activities, findings, or conclusions of the individual Working Groups or the Task Force as a whole.

Relevant U.S. and Canadian Legal Framework

United States

The Secretary of Energy directed the Department of Energy (DOE) to gather information and conduct an investigation to examine the cause or causes of the August 14, 2003 blackout. In initiating this effort, the Secretary exercised his authority under section 11 of the Energy Supply and Environmental Coordination Act of 1974, and section 13 of the Federal Energy Administration Act of 1974, to gather energy-related information and conduct investigations. This authority gives him and the DOE the ability to collect such energy information as he deems necessary to assist in the formulation of energy policy, to conduct investigations at reasonable times and in a reasonable manner, and to conduct physical inspections at energy facilities and business premises. In addition, DOE can inventory and sample any stock of fuels or energy sources therein, inspect and copy records, reports, and documents from which energy information has been or is being compiled and to question such persons as it deems necessary. DOE worked closely with Natural Resources Canada and NERC on the investigation.

Canada

Minister Dhaliwal, as the Minister responsible for Natural Resources Canada, was appointed by Prime Minister Chrétien as the Canadian Co-Chair of the Task Force. Minister Dhaliwal worked closely with his American Co-Chair, Secretary of Energy Abraham, as well as NERC and his provincial counterparts in carrying out his responsibilities. When NRCan Minister R. John Efford assumed his role as the new Canadian Co-Chair, he continued to work closely with Secretary Abraham and the three Working Groups.

Under Canadian law, the Task Force was characterized as a non-statutory, advisory body that does not have independent legal personality. The Task Force did not have any power to compel evidence or witnesses, nor was it able to conduct searches or seizures. In Canada, the Task Force relied on voluntary disclosure for obtaining information pertinent to its work.

Oversight and Coordination

The Task Force's U.S. and Canadian coordinators held frequent conference calls to ensure that all components of the investigation were making timely progress. They briefed both Secretary Abraham and Minister R. John Efford (Minister Dhaliwal, Phase I) regularly and provided weekly summaries from all components on the progress of the investigation. During part of Phase I, the leadership of the electric system investigation team held daily conference calls to address analytical and process issues important to the investigation. The three Working Groups held weekly conference calls to enable the investigation teams to update the Working Group members on the state of the overall analysis. Conference calls also focused on the analysis updates and the need to ensure public availability of all inputs to the development of recommendations. Working Group members attended panels and face-to-face meetings to review drafts of the report.

Electric System Investigation Phase I Investigative Process

Collection of Data and Information from ISOs, Utilities, States, and the Province of Ontario

On Tuesday, August 19, 2003, investigators affiliated with the U.S. Department of Energy (DOE) began interviewing control room operators and other key officials at the ISOs and the companies most directly involved with the initial stages of the outage. In addition to the information gained in the interviews, the interviewers sought information and data about control room operations and practices, the organization's system status and conditions on August 14, the organization's operating procedures and guidelines, load limits on its system, emergency planning and procedures, system security analysis tools and procedures, and practices for voltage and frequency monitoring. Similar interviews were held later with staff at Ontario's Independent Electricity Market Operator (IMO) and Hydro One in Canada.

On August 22 and 26, NERC directed the reliability coordinators at the ISOs to obtain a wide range of data and information from the control area coordinators under their oversight. The data requested included System Control and Data Acquisition (SCADA) logs, Energy Management System (EMS) logs, alarm logs, data from local digital fault recorders, data on transmission line and generator "trips" (i.e., automatic disconnection to prevent physical damage to equipment), state estimator data, operator logs and transcripts, and information related to the operation of capacitors, phase shifting transformers, load shedding, static var compensators, special protection schemes or stability controls, and high-voltage direct current (HVDC) facilities. NERC issued another data request to FirstEnergy on September 15 for copies of studies since 1990 addressing voltage support, reactive power supply, static capacitor applications, voltage requirements, import or transfer capabilities (in relation to reactive capability or voltage levels), and system impacts associated with unavailability of the Davis-Besse plant. All parties were instructed that data and information provided to either DOE or NERC did not have to be submitted a second time to the other entity—all material provided would go into a common data base.

For the Interim Report the investigative team held three technical conferences (August 22, September 8-9, and October 1-3) with the RTOs and ISOs and key utilities aimed at clarifying the data received, filling remaining gaps in the data, and developing a shared understanding of the data's implications.

Data "Warehouse"

The data collected by the investigative team was organized in an electronic repository containing thousands of transcripts, graphs, generator and transmission data and reports at the NERC headquarters in Princeton, New Jersey. The warehouse contains more than 20 gigabytes of information, in more than 10,000 files. This established a set of validated databases that the analytic teams could access as needed.

Individual investigative teams conducted their activities through a number of in-person meetings as well as conference calls and e-mail communications over the months of the investigation. Detailed investigative team findings will be included in upcoming technical reports issued by NERC.

The following were the information sources for the Electric System Investigation:

- Interviews conducted by members of the U.S.-Canada Electric Power System Outage Investigation Team with personnel at all of the utilities, control areas and reliability coordinators in the weeks following the blackout.
- Three fact-gathering meetings conducted by the Investigation Team with personnel from the above organizations on August 22, September 8 and 9, and October 1 to 3, 2003.
- Three public hearings held in Cleveland, Ohio; New York City, New York; and Toronto, Ontario.
- Two technical conferences held in Philadelphia, Pennsylvania, and Toronto, Canada.
- Materials provided by the above organizations in response to one or more data requests from the Investigation Team.
- All taped phone transcripts between involved operations centers.
- Additional interviews and field visits with operating personnel on specific issues in October 2003 and January 2004.
- Field visits to examine transmission lines and vegetation at short-circuit locations.
- Materials provided by utilities and state regulators in response to data requests on vegetation management issues.
- Detailed examination of thousands of individual relay trips for transmission and generation events.

Data Exploration and Requirements

This group requested data from the following control areas and their immediate neighbors: MISO, MECS, FE, PJM, NYISO, ISO-NE, and IMO. The data and exploration and requirements group's objective was to identify industry procedures that are in place today for collecting information following large-scale transmission related power outages and to assess those procedures in terms of the August 14, 2003 power outage investigation.

They sought to:

- Determine what happened in terms of immediate causes, sequence of events, and resulting consequences;
- Understand the failure mechanism via recordings of system variables such as frequency, voltages, and flows;
- Enable disturbance re-creation using computer models for the purposes of understanding the mechanism of failure, identifying ways to avoid or mitigate future failures, and assessing and improving the integrity of computer models;
- Identify deeper, underlying factors contributing to the failure (e.g., general policies, standard practices, communication paths, organizational cultures).

Sequence of Events

More than 800 events occurred during the blackout of August 14. The events included the opening and closing of transmission lines and associated breakers and switches, the opening of transformers and associated breakers, and the tripping and starting of generators and associated breakers. Most of these events occurred in the few minutes of the blackout cascade between 16:06 and 16:12 EDT. To properly analyze a blackout of this magnitude, an accurate knowledge of the sequence of events must be obtained before any analysis of the blackout can be performed.

Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was variation from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized to the National Institute of Standards and Technology (NIST) standard clock in Boulder, CO. Validating the timing of specific events became a large, important, and sometimes difficult task. This work was also critical to the issuance by the Task Force on September 12 of a "timeline" for the outage. The timeline briefly described the principal events, in sequence, leading up to the initiation of the outage's cascade phase, and then in the cascade itself. The timeline was not intended, however, to address the causal relationships among the events described, or to assign fault or responsibility for the blackout. All times in the chronology are in Eastern Daylight Time.

System Modeling and Simulation Analysis

The system modeling and simulation team (SMST) replicated system conditions on August 14 and the events leading up to the blackout. The modeling reflects the state of the electric system. Once benchmarked to actual conditions at selected critical times on August 14, it allowed analysts to conduct a series of sensitivity studies to determine if the system was stable and within limits at each point in time leading up to the cascade. The analysis also confirmed when the system became unstable and allowed analysts to test whether measures such as load-shedding would have prevented the cascade.

This team consisted of a number of NERC staff and persons with expertise in areas necessary to read and interpret all of the data logs, digital fault recorder information, sequence of events recorders information, etc. The team consisted of about 40 people involved at various different times with additional experts from the affected areas to understand the data.

Overall, this team:

- Created steady-state power flow cases for observed August 14 system conditions starting at 15:00 EDT through about 16:05 EDT (when powerflow simulations were no longer adequate), about the time of the Sammis-Star 345-kV outage.
- Compiled relevant data for dynamic modeling of affected systems (e.g. generator dynamic models, load characteristics, special protection schemes, etc.).
- Performed rigorous contingency analysis (over 800 contingencies in Eastern Interconnection run) to determine if the system was within operating within thermal and voltage limits, and within limits for possible further contingencies (N-1 contingencies) prior to and during the initial events of the blackout sequence.
- Performed sensitivity analysis to determine the significance of pre-existing conditions such as transmission outages in Cinergy and Dayton, and the earlier loss of Eastlake unit 5 generation.
- Performed "what-if" analysis to determine potential impacts of remedial actions such as reclosing of outages facilities during the sequence of events, load shedding, generation redispatch, and combinations of load shedding and redispatch.
- Compared transaction tags for August 14, to show how they matched up with those of other days in 2003 and 2002.
- Analyzed the transactions and generation dispatch changes used to bring replacement power for the loss of Eastlake 5 generation into FirstEnergy, to determine where the replacement power came from.
- Analyzed the performance of the Interchange Distribution Calculator (IDC) and its potential capability to help mitigate the overloads.

The SMST began its efforts using the base case data and model provided by FirstEnergy as its foundation.

The modeling and system studies work was performed under the guidance of a specially formed MAAC-ECAR-NPCC (MEN) Coordinating Group, consisting of the Regional Managers from those three regions impacted by the blackout, and their respective regional chairmen or designees.

Assessment of Operations Tools, SCADA/EMS, Communications, and Operations Planning

The Operations Tools, SCADA/EMS, Communications, and Operations Planning Team assessed the observability of the electric system to operators and reliability coordinators, and the availability and effectiveness of operational (real-time and day-ahead) reliability assessment tools, including redundancy of views and the ability to observe the "big picture" regarding bulk electric system conditions. The team investigated operating practices and effectiveness of operating entities and reliability coordinators in the affected area. This team investigated all aspects of the blackout related to operator and reliability coordinator knowledge of system conditions, action or inactions, and communications.

The Operations and Tools team conducted extensive interviews with operating personnel at the affected facilities. They participated in the technical investigation meetings with affected operators in August, September and October and reviewed the August 14 control room transcripts in detail. This group investigated the performance of the MISO and FirstEnergy EMS hardware and software and its impact on the blackout, and looked at operator training (including the use of formal versus "on-the-job" training) and the communications and interactions between the operations and information technology support staff at both organizations.

Frequency/ACE Analysis

The Frequency/ACE Team analyzed potential frequency anomalies that may have occurred on August 14, as compared to typical interconnection operations. The team also determined whether there were any unusual issues with control performance and frequency and any effects they may have had related to the cascading failure, and whether frequency-related anomalies were contributing factors or symptoms of other problems leading to the cascade.

Assessment of Transmission System Performance, Protection, Control, Maintenance, and Damage

This team investigated the causes of all transmission facility automatic operations (trips and reclosings) leading up to and through to the end of the cascade on all facilities greater than 100 kV. Included in the review were relay protection and remedial action schemes, including under-frequency load-shedding and identification of the cause of each operation and any misoperations that may have occurred. The team also assessed transmission facility maintenance practices in the affected area as compared to good utility practice and identified any transmission equipment that was damaged as a result of the cascading outage. The team reported patterns and conclusions regarding what caused transmission facilities to trip; why did the cascade extend as far as it did and not further into other systems; any misoperations and the effect those misoperations had on the outage; and any transmission equipment damage. Also the team reported on the transmission facility maintenance practices of entities in the affected area compared to good utility practice.

Assessment of Generator Performance, Protection, Controls, Maintenance, and Damage

This team investigated the cause of generator trips for all generators with a 10 MW or greater nameplate rating leading to and through the end of the cascade. The review included the cause for the generator trips, relay targets, unit power runbacks, and voltage/reactive power excursions. The team reported any generator equipment that was damaged as a result of the cascading outage. The team reported on patterns and conclusions regarding what caused generation facilities to trip. The team identified any unexpected performance anomalies or unexplained events. The team assessed generator maintenance practices in the affected area as compared to good utility practice. The team analyzed the coordination of generator under-frequency settings with transmission settings, such as under-frequency load shedding. The team gathered and analyzed data on affected nuclear units and worked with the Nuclear Regulatory Commission to address U.S. nuclear unit issues.

The Generator Performance team sent out an extensive data request to generator owners during Phase I of the investigation, but did not receive the bulk of the responses until Phase II. The analysis in this report uses the time of generator trip as it was reported by the plant owner, or the time when the generator ceased feeding power into the grid as determined by a system monitoring device, and synchronized those times to other known grid events as best as possible. However, many generation owners offered little information on the cause of unit trips or key information on conditions at their units, so it may never be possible to fully determine what happened to all the generators affected by the blackout, and why they performed as they did. In particular, it is not clear what point in time each reported generator trip time reflects—i.e., when in the cycle between when the generator first detected the condition which caused it to trip, or several seconds later when it actually stopped feeding power into the grid. This lack of clear data hampered effective investigation of generator issues.

Vegetation Management

For Phase I the Vegetation/Right of Way Team conducted a field investigation into the contacts that occurred between trees and conductors on August 14 within the FirstEnergy, Dayton Power & Light and Cinergy service areas. The team also examined detailed information gained from data requests to these and other utilities, including historical outages from tree contacts on these lines. These findings were included in the Interim Report and detailed in an interim report on utility vegetation management, posted at http://www.ferc.gov/cust-protect/moi/uvm-initial-report.pdf.

The team also requested information from the public utility commissions in the blackout area on any state requirements for transmission vegetation management and right-of-way maintenance.

Beginning in Phase I and continuing into Phase II, the Vegetation/ROW team looked in detail at the vegetation management and ROW maintenance practices for the three utilities above, and compared them to accepted utility practices across North America. Issues examined included ROW legal clearance agreements with landowners, budgets, tree-trimming cycles, organization structure, and use of herbicides. Through CN Utility Consulting, the firm hired by FERC to support the blackout investigation, the Vegetation/ROW team also identified "best practices" for transmission ROW management. They used those practices to evaluate the performance of the three utilities involved in August 14 line outages and also to evaluate the effectiveness of utility vegetation management practices generally.

On March 2, 2004, FERC released CN Utility Consulting's "Utility Vegetation Management Final Report" (see http://www.ferc.gov/cust-protect/moi/uvm-final-report.pdf).

Root Cause Analysis

The investigation team used a technique called root cause analysis to help guide the overall investigation process in an effort to identify root causes and contributing factors leading to the start of the blackout in Ohio. The root cause analysis team worked closely with the technical investigation teams providing feedback and queries on additional information. Also, drawing on other data sources as needed, the root cause analysis verified facts regarding conditions and actions (or inactions) that contributed to the blackout.

Root cause analysis is a systematic approach to identifying and validating causal linkages among conditions, events, and actions (or inactions) leading up to a major event of interest—in this case the August 14 blackout. It has been successfully applied in investigations of events such as nuclear power plant incidents, airplane crashes, and the recent Columbia space shuttle disaster.

Root cause analysis is driven by facts and logic. Events and conditions that may have helped to cause the major event in question are described in factual terms, and causal linkages are established between the major event and earlier conditions or events. Such earlier conditions or events are examined in turn to determine their causes, and at each stage the investigators ask whether the particular condition or event could have developed or occurred if a proposed cause (or combination of causes) had not been present. If the particular event being considered could have occurred without the proposed cause (or combination of causes), the proposed cause or combination of causes is dropped from consideration and other possibilities are considered.

Root cause analysis typically identifies several or even many causes of complex events; each of the various branches of the analysis is pursued until either a "root cause" is found or a non-correctable condition is identified. (A condition might be considered as non-correctable due to existing law, fundamental policy, laws of physics, etc.). Sometimes a key event in a causal chain leading to the major event could have been prevented by timely action by one or another party; if such action was feasible, and if the party had a responsibility to take such action, the failure to do so becomes a root cause of the major event.

Phase II

On December 12, 2003, Paul Martin was elected as the new Prime Minister of Canada and assumed responsibility for the Canadian section of the Power System Outage Task Force. Prime Minister Martin appointed R. John Efford as the new Minister of Natural Resources Canada and co-chair of the Task Force.

Press releases, a U.S. Federal Register notice, and ads in the Canadian press notified the public and stakeholders of Task Force developments. All public statements were released to the media and are available on the OETD and the NRCan web sites.

Several of the investigative teams began their work during Phase I and completed it during Phase II. Other teams could not begin their investigation into the events related to the cascade and blackout, beginning at 16:05:57 EDT on August 14, 2003, until analysis of the Ohio events before that point was completed in Phase I.

System Planning, Design and Studies Team

The SPDST studied reactive power management, transactions scheduling, system studies and system operating limits for the Ohio and ECAR areas. In addition to the data in the investigation data warehouse, the team submitted six comprehensive data requests to six control areas and reliability coordinators, including FirstEnergy, to build the foundation for its analyses. The team examined reactive power and voltage management policies, practices and criteria and compared them to actual and modeled system conditions in the affected area and neighboring systems. They assessed the process of assessing and approving transaction schedules and tags and the coordination of those schedules and transactions in August, 2003, and looked at the impact of tagged transactions on key facilities on August 14. Similarly, the team examined system operating limits in effect for the affected area on August 14, how they had been determined, and whether they were appropriate to the grid as it existed in August 2003. They reviewed system studies conducted by FirstEnergy and ECAR for 2003 and prior years, including the methodologies and assumptions used in those studies and how those were coordinated across adjoining control areas and councils. The SPDST also compared how the studied conditions compared to actual conditions on August 14. For all these matters, the team compared the policies, studies and practices to good utility practices.

The SPDST worked closely with the Modeling and System Simulation Team. They used data provided by the control areas, RTOs and ISOs on actual system conditions across August 2003, and NERC Tag Dump and TagNet data. To do the voltage analyses, the team started with the MSST's base case data and model of the entire Eastern Interconnection, then used a more detailed model of the FE area provided by FirstEnergy. With these models they conducted extensive PV and VQ analyses for different load levels and contingency combinations in the Cleveland-Akron area, running over 10,000 different power flow simulations. Team members have extensive experience and expertise in long-term and operational planning and system modeling.

NERC Standards, Procedures and Compliance Team

The SP&C team was charged with reviewing the NERC Operating Policies and Planning Standards for any violations that occurred in the events leading up to and during the blackout, and assessing the sufficiency or deficiency of NERC and regional reliability standards, policies and procedures. They were also directed to develop and conduct audits to assess compliance with the NERC and regional reliability standards as relevant to the cause of the outage.

The team members, all experienced participants in the NERC compliance and auditing program, examined the findings of the Phase I investigation in detail, building particularly upon the root cause analysis. They looked independently into many issues, conducting additional interviews as needed. The team distinguished between those violations which could be clearly proven and those which were problematic but not fully provable. The SP&C team offered a number of conclusions and recommendations to improve operational reliability, NERC standards, the standards development process and the compliance program.

Dynamic Modeling of the Cascade

This work was conducted as an outgrowth of the work done by the System Modeling and Simulation team in Phase I, by a team composed of the NPCC System Studies-38 Working Group on Inter-Area Dynamic Analysis, augmented by representatives from ECAR, MISO, PJM and SERC. Starting with the steady-state power flows developed in Phase I, they moved the analysis forward across the Eastern Interconnection from 16:05:50 EDT on in a series of first steady-state, then dynamic simulations to understand how conditions changed across the grid.

This team is using the model to conduct a series of "what if" analyses, to better understand what conditions contributed to the cascade and what might have happened if events had played out differently. This work is described further within Chapter 6.

Additional Cascade Analysis

The core team for the cascade investigation drew upon the work of all the teams to understand the cascade after 16:05:57. The investigation's official Sequence of Events was modified and corrected as appropriate as additional information came in from asset owners, and as modeling and other investigation revealed inaccuracies in the initial data reports. The team issued additional data requests and looked closely at the data collected across the period of the cascade. The team organized the analysis by attempting to link the individual area and facility events to the power flows, voltages and frequency data recorded by Hydro One's PSDRs (as seen in Figures 6.16 and 6.25) and similar data sets collected elsewhere. This effort improved the team's understanding of the interrelationships between the interaction, timing and impacts of lines, loads and generation trips, which are now being confirmed by dynamic modeling. Graphing, mapping and other visualization tools also created insights into the cascade, as with the revelation of the role of zone 3 relays in accelerating the early spread of the cascade within Ohio and Michigan.

The team was aided in its work by the ability to learn from the studies and reports on the blackout completed by various groups outside the investigation, including those by the Public Utility Commission of Ohio, the Michigan Public Service Commission, the New York ISO, ECAR and the Public Service Commission of New York.

Beyond the work of the Electric System investigation, the Security and Nuclear investigation teams conducted additional analyses and updated their interim reports with the additional findings.

Preparation of Task Force Recommendations

Public and stakeholder input was an important component in the development of the Task Force's recommendations. The input received covered a wide range of subjects, including enforcement of reliability standards, improving communications, planning for responses to emergency conditions, and the need to evaluate market structures. See Appendix C for a list of contributors.

Three public forums and two technical conferences were held to receive public comments on the Interim Report and suggested recommendations for consideration by the Task Force. These events were advertised by various means, including announcements in the *Federal Register* and the *Canada Gazette*, advertisements in local newspapers in the U.S., invitations to industry through NERC, invitations to the affected state and provincial regulatory bodies, and government press releases. All written inputs received at these meetings and conferences were posted for additional comment on public websites maintained by the U.S. Department of Energy and Natural Resources Canada (www.electricity.doe.gov and www.nrcan.gc.ca, respectively). The transcripts from the meetings and conferences were also posted on these websites.

- Members of all three Working Groups participated in public forums in Cleveland, Ohio (December 4, 2003), New York City (December 5, 2003), and Toronto, Ontario (December 8, 2003).
- The ESWG held two technical conferences, in Philadelphia, Pennsylvania (December 16, 2003), and Toronto, Ontario (January 9, 2004).
- The NWG also held a public meeting on nuclear-related issues pertaining to the blackout at the U.S. Nuclear Regulatory Commission headquarters in Rockville, Maryland (January 6, 2004).

The electric system investigation team also developed an extensive set of technical findings based on team analyses and cross-team discussions as the Phase I and Phase II work progressed. Many of these technical findings were reflected in NERC's actions and initiatives of February 10, 2004. In turn, NERC's actions and initiatives received significant attention in the development of the Task Force's recommendations.

The SWG convened in January 2004 in Ottawa to review the Interim Report. The SWG also held virtual meetings with the investigative team leads and working group members.

Similarly, the ESWG conducted weekly telephone conferences and it held face-to-face meetings on January 30, March 3, and March 18, 2004.

Appendix C

List of Commenters

The individuals listed below either commented on the Interim Report, provided suggestions for recommendations to improve reliability, or both. Their input was greatly appreciated. Their comments can be viewed in full or in summary at http://www.nrcan.gc.ca or at http://www.electricity.doe.gov.

Abbott, Richard E.	Personal comment
Adams, Tom	Energy Probe
Akerlund, John	Uninterruptible Power Networks UPN AB
Alexander, Anthony J.	FirstEnergy
Allen, Eric	New York ISO
Barrie, David	Hydro One
Benjamin, Don	North American Electric Reliability Council (NERC)
Besich, Tom	Electric power engineer
Blasiak, James L.	DykemaGossett PLLC for International Transmission Company (ITC)
Booth, Chris	Experienced Consultants LLC
Boschmann, Armin	Manitoba Hydro
Brown, Glenn W.	New Brunswick Power Corp; NPCC Representative & Chairman, NERC Disturbance Analysis Working Group
Burke, Thomas J.	Orion Associates International, Inc.
Burrell, Carl	IMO Ontario
Bush, Tim	Consulting
Calimano, Michael	New York ISO
Cañizares, Claudio A.	University of Waterloo, Ontario Canada
Carpentier, Philippe	French grid operator
Carson, Joseph P.	Personal comment
Casazza, J. A.	Power Engineers Seeking Truth
Chen, Shihe	Power Systems Business Group, CLP Power Hong Kong Ltd.
Church, Bob	Management Consulting Services, Inc.
Clark, Harrison	Harrison K. Clark
Cook, David	NERC
Cummings, Bob	Director of Reliability Assessments and Support Services, NERC
Das, K K	IEEE member, PowerGrid Corporation of India Limited
Delea, F. J.	Power Engineers Seeking Truth
Delea, Frank	ConEdison
Divan, Deepak	Soft Switching Technologies
Doumtchenko, Victoria	MPR Associates
Duran, Pat	IMO Ontario
Durkin, Charles J.	Northeast Power Coordinating Council (NPCC)
Eggertson, Bill	Canadian Association for Renewable Energies

Fernandez, Rick	Personal comment
Fidrych, Mark	Western Area Power Authority (WAPA) and Chairman of the NERC Operating Committee
Furuya, Toshihiko	Tokyo Electric Power Co., Inc.
Galatic, Alex	Personal comment
Garg, Ajay	Hydro One Networks Inc.
Goffin, Dave	Canadian Chemical Producers Assocation
Gruber, William M. Ondrey	Attorney
Guimond, Pierre	Canadian Nuclear Association
Gurdziel, Tom	Personal comment
Hakobyan, Spartak and Gurgen	Personal comment
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Jeyapalan, Jey K.	Jeyapalan & Associates, LLC
Johnston, Sidney A.	Personal comment
Kane, Michael	Personal comment
Katsuras, George	Independent Electric Market Operator of Ontario
Kellat, Stephen	Personal comment
Kerr, Jack	Dominion Virginia Power
Kerr, Jack	Best Real-time Reliability Analysis Practices Task Force
Kershaw, Raymond K.	International Transmission Company
Kolodziej, Eddie	Personal comment
Konow, Hans	Canadian Electricity Association
Kormos, Mike	PJM
Kucey, Tim	National Energy Board (Canada)
Laugier, Alexandre	Personal comment
Lawson, Barry	National Rural Electric Cooperative Association
Lazarewicz, Matthew L.	Beacon Power Corp.
Lee, Stephen	Electric Power Research Institute
Leovy, Steve	Personal comment
Linda Campbell	Florida Reliability Coordinating Council
Loehr, G.C.	Power Engineers Seeking Truth
Love, Peter	Canadian Energy Efficiency Alliance
Macedo, Frank	Hydro One
Maliszewski, R.M.	Power Engineers Seeking Truth
McMonagle, Rob	Canadian Solar Industries Assocation
Meissner, Joseph	Personal comment

Middlestadt, Bill	Bonneville Power Administration
Milter, Carolyn	Cuyahoga County Board of Commissioners, and member, Community Advisory Panel; panel created for Cleveland Electric Illuminating Co. (later First Energy)
Mitchell, Terry	Excel Energy
Moore, Scott	AEP
Murphy, Paul	IMO Ontario
Museler, William J.	New York Independent System Operator
O'Keefe, Brian	Canadian Union of Public Employees
Oliver, Fiona	Canadian Energy Efficiency Alliance
Ormund, Peter	Mohawk College
Pennstone, Mike	Hydro One
Pereira, Les	Personal comment
Phillips, Margie	Pennsylvania Services Integration Consortium
Rocha, Paul X.	CenterPoint Energy
Ross, Don	Prince Edward Island Wind Co-Op
Rupp, Douglas B	Ada Core Technologies, Inc.
Sasson, Mayer	New York State Reliability Council
Schwerdt, Ed	Northeast Power Coordinating Council
Seppa, Tapani O.	The Valley Group, Inc.,
Silverstein, Alison	Federal Energy Regulatory Commission
Spears, J.	Personal comment
Spencer, Sidney	Personal comment
spider	Personal comment
Staniford, Stuart	Personal comment
Stephens, Eric B.	Ohio Consumers' Counsel (OCC)
Stewart, Bob	PG&E
Synesiou, John	IMS Corporation
Tarler, Howard A.	On behalf of Chairman William M. Flynn, New York State Department of Public Service
Tatro, Phil	National Grid Company
Taylor, Carson	Bonneville Power Administration
van Welie, Gordon	ISO New England Inc.
Van Zandt, Vickie	Bonneville Power Administration
Warren, Kim	IMO Ontario
Watkins, Don	Bonneville Power Administration
Wells, Chuck	OSISoft
Wiedman, Tom	ConEd
Wightman, Donald	Utility Workers Union of America
Wilson, John	Personal comment
Winter, Chris	Conservation Council of Ontario
Wright, C. Dortch	On behalf of New Jersey Governor James E. McGreevey
Zwergel, Dave	Midwest ISO

Appendix D

NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts

Preamble

The Board of Trustees recognizes the paramount importance of a reliable bulk electric system in North America. In consideration of the findings of the investigation into the August 14, 2003 blackout, NERC must take firm and immediate actions to increase public confidence that the reliability of the North American bulk electric system is being protected.

A key finding of the blackout investigators is that violations of existing NERC reliability standards contributed directly to the blackout. Pending enactment of federal reliability legislation creating a framework for enforcement of mandatory reliability standards, and with the encouragement of the Stakeholders Committee, the board is determined to obtain full compliance with all existing and future reliability standards and intends to use all legitimate means available to achieve that end. The board therefore resolves to:

- *Receive specific information on all violations of NERC standards, including the identities of the parties involved;*
- *Take firm actions to improve compliance with NERC reliability standards;*
- *Provide greater transparency to violations of standards, while respecting the confidential nature of some information and the need for a fair and deliberate due process; and*
- *Inform and work closely with the Federal Energy Regulatory Commission and other applicable federal, state, and provincial regulatory authorities in the United States, Canada, and Mexico as needed to ensure public interests are met with respect to compliance with reliability standards.*

The board expresses its appreciation to the blackout investigators and the Steering Group for their objective and thorough work in preparing a report of recommended NERC actions. With a few clarifications, the board approves the report and directs implementation of the recommended actions. The board holds the assigned committees and organizations accountable to report to the board the progress in completing the recommended actions, and intends itself to publicly report those results. The board recognizes the possibility that this action plan may have to be adapted as additional analysis is completed, but stresses the need to move forward immediately with the actions as stated.

Furthermore, the board directs management to immediately advise the board of any significant violations of NERC reliability standards, including details regarding the nature and potential reliability impacts of the alleged violations and the identity of parties involved. Management shall supply to the board in advance of board meetings a detailed report of all violations of reliability standards.

Finally, the board resolves to form a task force to develop guidelines for the board to consider with regard to the confidentiality of compliance information and disclosure of such information to regulatory authorities and the public.

Approved by the Board of Trustees 1
February 10, 2004

Overview of Investigation Conclusions

The North American Electric Reliability Council (NERC) has conducted a comprehensive investigation of the August 14, 2003 blackout. The results of NERC's investigation contributed significantly to the U.S./Canada Power System Outage Task Force's November 19, 2003 Interim Report identifying the root causes of the outage and the sequence of events leading to and during the cascading failure. NERC fully concurs with the conclusions of the Interim Report and continues to provide its support to the Task Force through ongoing technical analysis of the outage. Although an understanding of what happened and why has been resolved for most aspects of the outage, detailed analysis continues in several areas, notably dynamic simulations of the transient phases of the cascade and a final verification of the full scope of all violations of NERC and regional reliability standards that occurred leading to the outage.

From its investigation of the August 14 blackout, NERC concludes that:

- Several entities violated NERC operating policies and planning standards, and those violations contributed directly to the start of the cascading blackout.
- The existing process for monitoring and assuring compliance with NERC and regional reliability standards was shown to be inadequate to identify and resolve specific compliance violations before those violations led to a cascading blackout.
- Reliability coordinators and control areas have adopted differing interpretations of the functions, responsibilities, authorities, and capabilities needed to operate a reliable power system.
- Problems identified in studies of prior large-scale blackouts were repeated, including deficiencies in vegetation management, operator training, and tools to help operators better visualize system conditions.
- In some regions, data used to model loads and generators were inaccurate due to a lack of verification through benchmarking with actual system data and field testing.
- Planning studies, design assumptions, and facilities ratings were not consistently shared and were not subject to adequate peer review among operating entities and regions.
- Available system protection technologies were not consistently applied to optimize the ability to slow or stop an uncontrolled cascading failure of the power system.

Overview of Recommendations

The Board of Trustees approves the NERC Steering Group recommendations to address these shortcomings. The recommendations fall into three categories.

Actions to Remedy Specific Deficiencies: Specific actions directed to First Energy (FE), the Midwest Independent System Operator (MISO), and the PJM Interconnection, LLC (PJM) to correct the deficiencies that led to the blackout.

1. Correct the Direct Causes of the August 14, 2003 Blackout.

Strategic Initiatives: Strategic initiatives by NERC and the regional reliability councils to strengthen compliance with existing standards and to formally track completion of recommended actions from August 14, and other significant power system events.

2. Strengthen the NERC Compliance Enforcement Program.
3. Initiate Control Area and Reliability Coordinator Reliability Readiness Audits.
4. Evaluate Vegetation Management Procedures and Results.
5. Establish a Program to Track Implementation of Recommendations.

Technical Initiatives: Technical initiatives to prevent or mitigate the impacts of future cascading blackouts.

6. Improve Operator and Reliability Coordinator Training
7. Evaluate Reactive Power and Voltage Control Practices.
8. Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
9. Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities and Authorities.
10. Establish Guidelines for Real-Time Operating Tools.
11. Evaluate Lessons Learned During System Restoration.
12. Install Additional Time-Synchronized Recording Devices as Needed.
13. Reevaluate System Design, Planning and Operating Criteria.
14. Improve System Modeling Data and Data Exchange Practices.

Market Impacts

Many of the recommendations in this report have implications for electricity markets and market participants, particularly those requiring reevaluation or clarification of NERC and regional standards, policies and criteria. Implicit in these recommendations is that the NERC board charges the Market Committee with assisting in the implementation of the recommendations and interfacing with the North American Energy Standards Board with respect to any necessary business practices.

Recommendation to Remedy Specific Deficiencies

Recommendation 1. Correct the Direct Causes of the August 14, 2003 Blackout.

NERC's technical analysis of the August 14 blackout leads it to fully concur with the Task Force Interim Report regarding the direct causes of the blackout. The report stated that the principal causes of the blackout were that FE did not maintain situational awareness of conditions on its power system and did not adequately manage tree growth in its transmission rights-of-way. Contributing factors included ineffective diagnostic support provided by MISO as the reliability coordinator for FE and ineffective communications between MISO and PJM.

NERC will take immediate and firm actions to ensure that the same deficiencies that were directly causal to the August 14 blackout are corrected. These steps are necessary to assure electricity customers, regulators and others with an interest in the reliable delivery of electricity that the power system is being operated in a manner that is safe and reliable, and that the specific causes of the August 14 blackout have been identified and fixed.

Recommendation 1a: FE, MISO, and PJM shall each complete the remedial actions designated in Attachment A for their respective organizations and certify to the NERC board no later than June 30, 2004, that these specified actions have been completed. Furthermore, each organization shall present its detailed plan for completing these actions to the NERC committees for technical review on March 23-24, 2004, and to the NERC board for approval no later than April 2, 2004.

Recommendation 1b: The NERC Technical Steering Committee shall immediately assign a team of experts to assist FE, MISO, and PJM in developing plans that adequately address the issues listed in Attachment A, and other remedial actions for which each entity may seek technical assistance.

Strategic Initiatives to Assure Compliance with Reliability Standards and to Track Recommendations

Recommendation 2. Strengthen the NERC Compliance Enforcement Program.

NERC's analysis of the actions and events leading to the August 14 blackout leads it to conclude that several violations of NERC operating policies contributed directly to an uncontrolled, cascading outage on the Eastern Interconnection. NERC continues to investigate additional violations of NERC and regional reliability standards and expects to issue a final report of those violations in March 2004.

In the absence of enabling legislation in the United States and complementary actions in Canada and Mexico to authorize the creation of an electric reliability organization, NERC lacks legally sanctioned authority to enforce compliance with its reliability rules. However, the August 14 blackout is a clear signal that voluntary compliance with reliability rules is no longer adequate. NERC and the regional reliability councils must assume firm authority to measure compliance, to more transparently report significant violations that could risk the integrity of the interconnected power system, and to take immediate and effective actions to ensure that such violations are corrected.

Violations of NERC standards identified in the November 19, 2003 Interim Report:

1. Following the outage of the Chamberlin-Harding 345 kV line, FE did not take the necessary actions to return the system to a safe operating state within 30 minutes (violation of NERC Operating Policy 2).
2. FE did not notify other systems of an impending system emergency (violation of NERC Operating Policy 5).
3. FE's analysis tools were not used to effectively assess system conditions (violation of NERC Operating Policy 5).
4. FE operator training was inadequate for maintaining reliable conditions (violation of NERC Operating Policy 8).
5. MISO did not notify other reliability coordinators of potential problems (violation of NERC Operating Policy 9).

Recommendation 2a: Each regional reliability council shall report to the NERC Compliance Enforcement Program within one month of occurrence all significant[1] violations of NERC operating policies and planning standards and regional standards, whether verified or still under investigation. Such reports shall confidentially note details regarding the nature and potential reliability impacts of the alleged violations and the identity of parties involved. Additionally, each regional reliability council shall report quarterly to NERC, in a format prescribed by NERC, all violations of NERC and regional reliability council standards.

Recommendation 2b: Being presented with the results of the investigation of any significant violation, and with due consideration of the surrounding facts and circumstances, the NERC board shall require an offending organization to correct the violation within a specified time. If the board determines that an offending organization is non-responsive and continues to cause a risk to the reliability of the interconnected power systems, the board will seek to remedy the violation by requesting assistance of the appropriate regulatory authorities in the United States, Canada, and Mexico.

[1] Although all violations are important, a significant violation is one that could directly reduce the integrity of the interconnected power systems or otherwise cause unfavorable risk to the interconnected power systems. By contrast, a violation of a reporting or administrative requirement would not by itself generally be considered a significant violation.

Recommendation 2c: The Planning and Operating Committees, working in conjunction with the Compliance Enforcement Program, shall review and update existing approved and draft compliance templates applicable to current NERC operating policies and planning standards; and submit any revisions or new templates to the board for approval no later than March 31, 2004. To expedite this task, the NERC President shall immediately form a Compliance Template Task Force comprised of representatives of each committee. The Compliance Enforcement Program shall issue the board-approved compliance templates to the regional reliability councils for adoption into their compliance monitoring programs.

This effort will make maximum use of existing approved and draft compliance templates in order to meet the aggressive schedule. The templates are intended to include all existing NERC operating policies and planning standards but can be adapted going forward to incorporate new reliability standards as they are adopted by the NERC board for implementation in the future.

When the investigation team's final report on the August 14 violations of NERC and regional standards is available in March, it will be important to assess and understand the lapses that allowed violations to go unreported until a large-scale blackout occurred.

Recommendation 2d: The NERC Compliance Enforcement Program and ECAR shall, within three months of the issuance of the final report from the Compliance and Standards investigation team, evaluate the identified violations of NERC and regional standards, as compared to previous compliance reviews and audits for the applicable entities, and develop recommendations to improve the compliance process.

Recommendation 3. Initiate Control Area and Reliability Coordinator Reliability Readiness Audits.

In conducting its investigation, NERC found that deficiencies in control area and reliability coordinator capabilities to perform assigned reliability functions contributed to the August 14 blackout. In addition to specific violations of NERC and regional standards, some reliability coordinators and control areas were deficient in the performance of their reliability functions and did not achieve a level of performance that would be considered acceptable practice in areas such as operating tools, communications, and training. In a number of cases there was a lack of clarity in the NERC policies with regard to what is expected of a reliability coordinator or control area. Although the deficiencies in the NERC policies must be addressed (see Recommendation 9), it is equally important to recognize that standards cannot prescribe all aspects of reliable operation and that minimum standards present a threshold, not a target for performance. Reliability coordinators and control areas must perform well, particularly under emergency conditions, and at all times strive for excellence in their assigned reliability functions and responsibilities.

Recommendation 3a: The NERC Compliance Enforcement Program and the regional reliability councils shall jointly establish a program to audit the reliability readiness of all reliability coordinators and control areas, with immediate attention given to addressing the deficiencies identified in the August 14 blackout investigation. Audits of all control areas and reliability coordinators shall be completed within three years and continue in a three-year cycle. The 20 highest priority audits, as determined by the Compliance Enforcement Program, will be completed by June 30, 2004.

Recommendation 3b: NERC will establish a set of baseline audit criteria to which regional criteria may be added. The control area requirements will be based on the existing NERC Control Area Certification Procedure. Reliability coordinator audits will include evaluation of reliability plans, procedures, processes, tools, personnel qualifications, and training. In addition to reviewing written documents, the audits will carefully examine the actual practices and preparedness of control areas and reliability coordinators.

Recommendation 3c: The reliability regions, with the oversight and direct participation of NERC, will audit each control area's and reliability coordinator's readiness to meet these audit criteria. FERC and other relevant regulatory agencies will be invited to participate in the audits, subject to the same confidentiality conditions as the other members of the audit teams.

Recommendation 4. Evaluate Vegetation Management Procedures and Results.

Ineffective vegetation management was a major cause of the August 14 blackout and also contributed to other historical large-scale blackouts, such on July 2-3, 1996 in the west. Maintaining transmission line rights-of-way (ROW), including maintaining safe clearances of energized lines from vegetation, under-build, and other obstructions[2] incurs a substantial ongoing cost in many areas of North America. However, it is an important investment for assuring a reliable electric system.

NERC does not presently have standards for ROW maintenance. Standards on vegetation management are particularly challenging given the great diversity of vegetation and growth patterns across North America. However, NERC's standards do require that line ratings are calculated so as to maintain safe clearances from all obstructions. Furthermore, in the United States, the National Electrical Safety Code (NESC) Rules 232, 233, and 234 detail the minimum vertical and horizontal safety clearances of overhead conductors from grounded objects and various types of obstructions. NESC Rule 218 addresses tree clearances by simply stating, "Trees that may interfere with ungrounded supply conductors should be trimmed or removed." Several states have adopted their own electrical safety codes and similar codes apply in Canada.

Recognizing that ROW maintenance requirements vary substantially depending on local conditions, NERC will focus attention initially on measuring performance as indicated by the number of high voltage line trips caused by vegetation rather than immediately move toward developing standards for

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[2] Vegetation, such as the trees that caused the initial line trips in FE that led to the August 14, 2003 outage is not the only type of obstruction that can breach the safe clearance distances from energized lines. Other examples include under-build of telephone and cable TV lines, train crossings, and even nests of certain large bird species.

ROW maintenance. This approach has worked well in the Western Electricity Coordinating Council (WECC) since being instituted after the 1996 outages.

Recommendation 4a: NERC and the regional reliability councils shall jointly initiate a program to report all bulk electric system[3] transmission line trips resulting from vegetation contact[4]. The program will use the successful WECC vegetation monitoring program as a model.

Recommendation 4b: Beginning with an effective date of January 1, 2004, each transmission operator will submit an annual report of all vegetation-related high voltage line trips to its respective reliability region. Each region shall assemble a detailed annual report of vegetation-related line trips in the region to NERC no later than March 31 for the preceding year, with the first reporting to be completed by March 2005 for calendar year 2004.

Vegetation management practices, including inspection and trimming requirements, can vary significantly with geography. Additionally, some entities use advanced techniques such as planting beneficial species or applying growth retardants. Nonetheless, the events of August 14 and prior outages point to the need for independent verification that viable programs exist for ROW maintenance and that the programs are being followed.

Recommendation 4c: Each bulk electric transmission owner shall make its vegetation management procedure, and documentation of work completed, available for review and verification upon request by the applicable regional reliability council, NERC, or applicable federal, state or provincial regulatory agency.

Should this approach of monitoring vegetation-related line outages and procedures prove ineffective in reducing the number of vegetation-related line outages, NERC will consider the development of minimum line clearance standards to assure reliability.

Recommendation 5. Establish a Program to Track Implementation of Recommendations.

The August 14 blackout shared a number of contributing factors with prior large-scale blackouts, including:

- Conductors contacting trees
- Ineffective visualization of power system conditions and lack of situational awareness
- Ineffective communications
- Lack of training in recognizing and responding to emergencies
- Insufficient static and dynamic reactive power supply
- Need to improve relay protection schemes and coordination

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[3] All transmission lines operating at 230 kV and higher voltage, and any other lower voltage lines designated by the regional reliability council to be critical to the reliability of the bulk electric system, shall be included in the program.

[4] A line trip includes a momentary opening and reclosing of the line, a lock out, or a combination. For reporting purposes, all vegetation-related openings of a line occurring within one 24-hour period should be considered one event. Trips known to be caused by severe weather or other natural disaster such as earthquake are excluded. Contact with vegetation includes both physical contact and arcing due to insufficient clearance.

It is important that recommendations resulting from system outages be adopted consistently by all regions and operating entities, not just those directly affected by a particular outage. Several lessons learned prior to August 14, if heeded, could have prevented the outage. WECC and NPCC, for example, have programs that could be used as models for tracking completion of recommendations. NERC and some regions have not adequately tracked completion of recommendations from prior events to ensure they were consistently implemented.

Recommendation 5a: NERC and each regional reliability council shall establish a program for documenting completion of recommendations resulting from the August 14 blackout and other historical outages, as well as NERC and regional reports on violations of reliability standards, results of compliance audits, and lessons learned from system disturbances. Regions shall report quarterly to NERC on the status of follow-up actions to address recommendations, lessons learned, and areas noted for improvement. NERC staff shall report both NERC activities and a summary of regional activities to the board.

Assuring compliance with reliability standards, evaluating the reliability readiness of reliability coordinators and control areas, and assuring recommended actions are achieved will be effective steps in reducing the chances of future large-scale outages. However, it is important for NERC to also adopt a process for continuous learning and improvement by seeking continuous feedback on reliability performance trends, not rely mainly on learning from and reacting to catastrophic failures.

Recommendation 5b: NERC shall by January 1, 2005 establish a reliability performance monitoring function to evaluate and report bulk electric system reliability performance.

Such a function would assess large-scale outages and near misses to determine root causes and lessons learned, similar to the August 14 blackout investigation. This function would incorporate the current Disturbance Analysis Working Group and expand that work to provide more proactive feedback to the NERC board regarding reliability performance. This program would also gather and analyze reliability performance statistics to inform the board of reliability trends. This function could develop procedures and capabilities to initiate investigations in the event of future large-scale outages or disturbances. Such procedures and capabilities would be shared between NERC and the regional reliability councils for use as needed, with NERC and regional investigation roles clearly defined in advance.

Technical Initiatives to Minimize the Likelihood and Impacts of Possible Future Cascading Outages

Recommendation 6. Improve Operator and Reliability Coordinator Training.

NERC found during its investigation that some reliability coordinators and control area operators had not received adequate training in recognizing and responding to system emergencies. Most notable was the lack of realistic simulations and drills for training and verifying the capabilities of operating personnel. This training deficiency contributed to the lack of situational awareness and failure to declare an emergency when operator intervention was still possible prior to the high speed portion of the sequence of events.

Recommendation 6: All reliability coordinators, control areas, and transmission operators shall provide at least five days per year of training and drills in system emergencies, using realistic simulations[5], for each staff person with responsibility for the real-time operation or reliability monitoring of the bulk electric system. This system emergency training is in addition to other training requirements. Five days of system emergency training and drills are to be completed prior to June 30, 2004, with credit given for documented training already completed since July 1, 2003. Training documents, including curriculum, training methods, and individual training records, are to be available for verification during reliability readiness audits.

NERC has published Continuing Education Criteria specifying appropriate qualifications for continuing education providers and training activities.

In the longer term, the NERC Personnel Certification Governance Committee (PCGC), which is independent of the NERC board, should explore expanding the certification requirements of system operating personnel to include additional measures of competency in recognizing and responding to system emergencies. The current NERC certification examination is a written test of the NERC Operating Manual and other references relating to operator job duties, and is not by itself intended to be a complete demonstration of competency to handle system emergencies.

Recommendation 7. Evaluate Reactive Power and Voltage Control Practices.

The August 14 blackout investigation identified inconsistent practices in northeastern Ohio with regard to the setting and coordination of voltage limits and insufficient reactive power supply. Although the deficiency of reactive power supply in northeastern Ohio did not directly cause the blackout, it was a contributing factor and was a significant violation of existing reliability standards.

In particular, there appear to have been violations of NERC Planning Standard I.D.S1 requiring static and dynamic reactive power resources to meet the performance criteria specified in Table I of

[5] The term "realistic simulations" includes a variety of tools and methods that present operating personnel with situations to improve and test diagnostic and decision-making skills in an environment that resembles expected conditions during a particular type of system emergency. Although a full replica training simulator is one approach, lower cost alternatives such as PC-based simulators, tabletop drills, and simulated communications can be effective training aids if used properly.

Planning Standard I.A on Transmission Systems. Planning Standard II.B.S1 requires each regional reliability council to establish procedures for generating equipment data verification and testing, including reactive power capability. Planning Standard III.C.S1 requires that all synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator. S2 of this standard also requires that generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units.

On one hand, the unsafe conditions on August 14 with respect to voltage in northeastern Ohio can be said to have resulted from violations of NERC planning criteria for reactive power and voltage control, and those violations should have been identified through the NERC and ECAR compliance monitoring programs (addressed by Recommendation 2). On the other hand, investigators believe these deficiencies are also symptomatic of a systematic breakdown of the reliability studies and practices in FE and the ECAR region that allowed unsafe voltage criteria to be set and used in study models and operations. There were also issues identified with reactive characteristics of loads, as addressed in Recommendation 14.

Recommendation 7a: The Planning Committee shall reevaluate within one year the effectiveness of the existing reactive power and voltage control standards and how they are being implemented in practice in the ten NERC regions. Based on this evaluation, the Planning Committee shall recommend revisions to standards or process improvements to ensure voltage control and stability issues are adequately addressed.

Recommendation 7b: ECAR shall no later than June 30, 2004 review its reactive power and voltage criteria and procedures, verify that its criteria and procedures are being fully implemented in regional and member studies and operations, and report the results to the NERC board.

Recommendation 8. Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.

The importance of automatic control and protection systems in preventing, slowing, or mitigating the impact of a large-scale outage cannot be stressed enough. To underscore this point, following the trip of the Sammis-Star line at 4:06, the cascading failure into parts of eight states and two provinces, including the trip of over 531 generating units and over 400 transmission lines, was completed in the next eight minutes. Most of the event sequence, in fact, occurred in the final 12 seconds of the cascade. Likewise, the July 2, 1996 failure took less than 30 seconds and the August 10, 1996 failure took only 5 minutes. It is not practical to expect operators will always be able to analyze a massive, complex system failure and to take the appropriate corrective actions in a matter of a few minutes. The NERC investigators believe that two measures would have been crucial in slowing or stopping the uncontrolled cascade on August 14:

- Better application of zone 3 impedance relays on high voltage transmission lines
- Selective use of under-voltage load shedding.

First, beginning with the Sammis-Star line trip, most of the remaining line trips during the cascade phase were the result of the operation of a zone 3 relay for a perceived overload (a combination of high amperes and low voltage) on the protected line. If used, zone 3 relays typically act as an overreaching backup to the zone 1 and 2 relays, and are not intentionally set to operate on a line overload. However, under extreme conditions of low voltages and large power swings as seen on August 14, zone 3 relays can operate for overload conditions and propagate the outage to a wider area by essentially causing the system to "break up". Many of the zone 3 relays that operated during the August 14 cascading outage were not set with adequate margins above their emergency thermal ratings. For the short times involved, thermal heating is not a problem and the lines should not be tripped for overloads. Instead, power system protection devices should be set to address the specific condition of concern, such as a fault, out-of-step condition, etc., and should not compromise a power system's inherent physical capability to slow down or stop a cascading event.

Recommendation 8a: All transmission owners shall, no later than September 30, 2004, evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions[6]. In each case that a zone 3 relay is set so as to trip on load under extreme conditions, the transmission operator shall reset, upgrade, replace, or otherwise mitigate the overreach of those relays as soon as possible and on a priority basis, but no later than December 31, 2005. Upon completing analysis of its application of zone 3 relays, each transmission owner may no later than December 31, 2004 submit justification to NERC for applying zone 3 relays outside of these recommended parameters. The Planning Committee shall review such exceptions to ensure they do not increase the risk of widening a cascading failure of the power system.

A second key finding with regard to system protection was that if an automatic under-voltage load shedding scheme had been in place in the Cleveland-Akron area on August 14, there is a high probability the outage could have been limited to that area.

Recommendation 8b: Each regional reliability council shall complete an evaluation of the feasibility and benefits of installing under-voltage load shedding capability in load centers within the region that could become unstable as a result of being deficient in reactive power following credible multiple-contingency events. The regions are to complete the initial studies and report the results to NERC within one year. The regions are requested to promote the installation of under-voltage load shedding capabilities within critical areas, as determined by the studies to be effective in preventing an uncontrolled cascade of the power system.

The NERC investigation of the August 14 blackout has identified additional transmission and generation control and protection issues requiring further analysis. One concern is that generating unit control and protection schemes need to consider the full range of possible extreme system conditions, such as the low voltages and low and high frequencies experienced on August 14. The team also noted that improvements may be needed in under-frequency load shedding and its coordination with generator under-and over-frequency protection and controls.

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[6] The NERC investigation team recommends that the zone 3 relay, if used, should not operate at or below 150% of the emergency ampere rating of a line, assuming a .85 per unit voltage and a line phase angle of 30 degrees.

Recommendation 8c: The Planning Committee shall evaluate Planning Standard III – System Protection and Control and propose within one year specific revisions to the criteria to adequately address the issue of slowing or limiting the propagation of a cascading failure. The board directs the Planning Committee to evaluate the lessons from August 14 regarding relay protection design and application and offer additional recommendations for improvement.

Recommendation 9. Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities and Authorities.

Ambiguities in the NERC operating policies may have allowed entities involved in the August 14 blackout to make different interpretations regarding the functions, responsibilities, capabilities, and authorities of reliability coordinators and control areas. Characteristics and capabilities necessary to enable prompt recognition and effective response to system emergencies must be specified.

The lack of timely and accurate outage information resulted in degraded performance of state estimator and reliability assessment functions on August 14. There is a need to review options for sharing of outage information in the operating time horizon (e.g. 15 minutes or less), so as to ensure the accurate and timely sharing of outage data necessary to support real-time operating tools such as state estimators, real-time contingency analysis, and other system monitoring tools.

On August 14, reliability coordinator and control area communications regarding conditions in northeastern Ohio were ineffective, and in some cases confusing. Ineffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade. Consistent application of effective communications protocols, particularly during emergencies, is essential to reliability. Alternatives should be considered to one-on-one phone calls during an emergency to ensure all parties are getting timely and accurate information with a minimum number of calls.

NERC operating policies do not adequately specify critical facilities, leaving ambiguity regarding which facilities must be monitored by reliability coordinators. Nor do the policies adequately define criteria for declaring transmission system emergencies. Operating policies should also clearly specify that curtailing interchange transactions through the NERC Transmission Loading Relief (TLR) Procedure is not intended as a method for restoring the system from an actual Operating Security Limit violation to a secure operating state.

Recommendation 9: The Operating Committee shall complete the following by June 30, 2004:

- **Evaluate and revise the operating policies and procedures, or provide interpretations, to ensure reliability coordinator and control area functions, responsibilities, and authorities are completely and unambiguously defined.**
- **Evaluate and improve the tools and procedures for operator and reliability coordinator communications during emergencies.**
- **Evaluate and improve the tools and procedures for the timely exchange of outage information among control areas and reliability coordinators.**

Recommendation 10. Establish Guidelines for Real-Time Operating Tools.

The August 14 blackout was caused by a lack of situational awareness that was in turn the result of inadequate reliability tools and backup capabilities. Additionally, the failure of FE's control computers and alarm system contributed directly to the lack of situational awareness. Likewise, MISO's incomplete tool set and the failure of its state estimator to work effectively on August 14 contributed to the lack of situational awareness.

Recommendation 10: The Operating Committee shall within one year evaluate the real-time operating tools necessary for reliable operation and reliability coordination, including backup capabilities. The Operating Committee is directed to report both minimum acceptable capabilities for critical reliability functions and a guide of best practices.

This evaluation should include consideration of the following:

- Modeling requirements, such as model size and fidelity, real and reactive load modeling, sensitivity analyses, accuracy analyses, validation, measurement, observability, update procedures, and procedures for the timely exchange of modeling data.
- State estimation requirements, such as periodicity of execution, monitoring external facilities, solution quality, topology error and measurement error detection, failure rates including times between failures, presentation of solution results including alarms, and troubleshooting procedures.
- Real-time contingency analysis requirements, such as contingency definition, periodicity of execution, monitoring external facilities, solution quality, post-contingency automatic actions, failure rates including mean/maximum times between failures, reporting of results, presentation of solution results including alarms, and troubleshooting procedures including procedures for investigating unsolvable contingencies.

Recommendation 11. Evaluate Lessons Learned During System Restoration.

The efforts to restore the power system and customer service following the outage were effective, considering the massive amount of load lost and the large number of generators and transmission lines that tripped. Fortunately, the restoration was aided by the ability to energize transmission from neighboring systems, thereby speeding the recovery. Despite the apparent success of the restoration effort, it is important to evaluate the results in more detail to determine opportunities for improvement. Blackstart and restoration plans are often developed through study of simulated conditions. Robust testing of live systems is difficult because of the risk of disturbing the system or interrupting customers. The August 14 blackout provides a valuable opportunity to apply actual events and experiences to learn to better prepare for system blackstart and restoration in the future. That opportunity should not be lost, despite the relative success of the restoration phase of the outage.

Recommendation 11a: The Planning Committee, working in conjunction with the Operating Committee, NPCC, ECAR, and PJM, shall evaluate the black start and system restoration performance following the outage of August 14, and within one year report to the NERC board the results of that evaluation with recommendations for improvement.

Recommendation 11b: All regional reliability councils shall, within six months of the Planning Committee report to the NERC board, reevaluate their procedures and plans to assure an effective blackstart and restoration capability within their region.

Recommendation 12. Install Additional Time-Synchronized Recording Devices as Needed.

A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices.

NERC Planning Standard I.F – Disturbance Monitoring does require location of recording devices for disturbance analysis. Often time, recorders are available, but they are not synchronized to a time standard. All digital fault recorders, digital event recorders, and power system disturbance recorders should be time stamped at the point of observation with a precise Global Positioning Satellite (GPS) synchronizing signal. Recording and time-synchronization equipment should be monitored and calibrated to assure accuracy and reliability.

Time-synchronized devices, such as phasor measurement units, can also be beneficial for monitoring a wide-area view of power system conditions in real-time, such as demonstrated in WECC with their Wide-Area Monitoring System (WAMS).

Recommendation 12a: The reliability regions, coordinated through the NERC Planning Committee, shall within one year define regional criteria for the application of synchronized recording devices in power plants and substations. Regions are requested to facilitate the installation of an appropriate number, type and location of devices within the region as soon as practical to allow accurate recording of future system disturbances and to facilitate benchmarking of simulation studies by comparison to actual disturbances.

Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization and, as necessary, install additional dynamic recorders.

Recommendation 13. Reevaluate System Design, Planning and Operating Criteria.

The investigation report noted that FE entered the day on August 14 with insufficient resources to stay within operating limits following a credible set of contingencies, such as the loss of the East Lake 5 unit and the Chamberlin-Harding line. NERC will conduct an evaluation of operations planning practices and criteria to ensure expected practices are sufficient and well understood. The review will reexamine fundamental operating criteria, such as n-1 and the 30-minute limit in preparing the system for a next contingency, and Table I Category C.3 of the NERC planning standards. Operations planning and operating criteria will be identified that are sufficient to ensure the system is in a known and reliable condition at all times, and that positive controls, whether manual or automatic, are available and appropriately located at all times to return the Interconnection to a secure condition. Daily operations planning, and subsequent real time operations planning will identify available system reserves to meet operating criteria.

Recommendation 13a: The Operating Committee shall evaluate operations planning and operating criteria and recommend revisions in a report to the board within one year.

Prior studies in the ECAR region did not adequately define the system conditions that were observed on August 14. Severe contingency criteria were not adequate to address the events of August 14 that led to the uncontrolled cascade. Also, northeastern Ohio was found to have insufficient reactive support to serve its loads and meet import criteria. Instances were also noted in the FE system and ECAR area of different ratings being used for the same facility by planners and operators and among entities, making the models used for system planning and operation suspect. NERC and the regional reliability councils must take steps to assure facility ratings are being determined using consistent criteria and being effectively shared and reviewed among entities and among planners and operators.

Recommendation 13b: ECAR shall no later than June 30, 2004 reevaluate its planning and study procedures and practices to ensure they are in compliance with NERC standards, ECAR Document No. 1, and other relevant criteria; and that ECAR and its members' studies are being implemented as required.

Recommendation 13c: The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, methods and practices used for system design, planning and analysis; and shall report the results and recommendations to the NERC board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information.

Regional reliability councils may consider assembling a regional database that includes the ratings of all bulk electric system (100 kV and higher voltage) transmission lines, transformers, phase angle regulators, and phase shifters. This database should be shared with neighboring regions as needed for system planning and analysis.

NERC and the regional reliability councils should review the scope, frequency, and coordination of interregional studies, to include the possible need for simultaneous transfer studies. Study criteria will be reviewed, particularly the maximum credible contingency criteria used for system analysis. Each control area will be required to identify, for both the planning and operating time horizons, the planned emergency import capabilities for each major load area.

Recommendation 14. Improve System Modeling Data and Data Exchange Practices.

The after-the-fact models developed to simulate August 14 conditions and events indicate that dynamic modeling assumptions, including generator and load power factors, used in planning and operating models were inaccurate. Of particular note, the assumptions of load power factor were overly optimistic (loads were absorbing much more reactive power than pre-August 14 models indicated). Another suspected problem is modeling of shunt capacitors under depressed voltage conditions. Regional reliability councils should establish regional power system models that enable the sharing of consistent, validated data among entities in the region. Power flow and transient stability simulations should be periodically compared (benchmarked) with actual system events to validate model data. Viable load (including load power factor) and generator testing programs are necessary to improve agreement between power flows and dynamic simulations and the actual system performance.

Recommendation 14: The regional reliability councils shall within one year establish and begin implementing criteria and procedures for validating data used in power flow models and dynamic simulations by benchmarking model data with actual system performance. Validated modeling data shall be exchanged on an inter-regional basis as needed for reliable system planning and operation.

During the data collection phase of the blackout investigation, when control areas were asked for information pertaining to merchant generation within their area, data was frequently not supplied. The reason often given was that the control area did not know the status or output of the generator at a given point in time. Another reason was the commercial sensitivity or confidentiality of such data.

Appendix E

List of Electricity Acronyms

AEP	American Electric Power
BPA	Bonneville Power Administration
CA	Control area
CNSC	Canadian Nuclear Safety Commission
DOE	Department of Energy (U.S.)
ECAR	East Central Area Reliability Coordination Agreement
EIA	Energy Information Administration (U.S. DOE)
EMS	Energy management system
ERCOT	Electric Reliability Council of Texas
ERO	Electric reliability organization
FE	FirstEnergy
FERC	Federal Energy Regulatory Commission (U.S.)
FRCC	Florida Reliability Coordinating Council
GW, GWh	Gigawatt, Gigawatt-hour
IEEE	Institute of Electrical and Electronics Engineers
IPP	Independent power producer
ISAC	Information Sharing and Analysis Center
kV, kVAr	Kilovolt, Kilovolt-Amperes-reactive
kW, kWh	Kilowatt, Kilowatt-hour
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MECS	Michigan Electrical Coordinated Systems
MVA, MVAr	Megavolt-Amperes, Megavolt-Amperes-reactive
MW, MWh	Megawatt, Megawatt-hour
NERC	North American Electric Reliability Council
NESC	National Electricity Safety Code
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission (U.S.)
NRCan	Natural Resources Canada
OASIS	Open Access Same Time Information Service
OETD	Office of Electric Transmission and Distribution (U.S. DOE)
PJM	PJM Interconnection
PUC	Public utility (or public service) commission (state)
RC	Reliability coordinator
ROW	Right-of-Way (transmission or distribution line, pipeline, etc.)
RRC	Regional reliability council
RTO	Regional Transmission Organization
SCADA	Supervisory control and data acquisition
SERC	Southeast Electric Reliability Council
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority (U.S.)
WECC	Western Electricity Coordinating Council

Appendix F

Electricity Glossary

AC: Alternating current; current that changes periodically (sinusoidally) with time.

ACE: Area Control Error in MW. A negative value indicates a condition of under-generation relative to system load and imports, and a positive value denotes over-generation.

Active Power: See "Real Power."

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

AGC: Automatic Generation Control is a computation based on measured frequency and computed economic dispatch. Generation equipment under AGC automatically responds to signals from an EMS computer in real time to adjust power output in response to a change in system frequency, tie-line loading, or to a prescribed relation between these quantities. Generator output is adjusted so as to maintain a target system frequency (usually 60 Hz) and any scheduled MW interchange with other areas.

Apparent Power: The product of voltage and current phasors. It comprises both active and reactive power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Blackstart Capability: The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the bulk electric system.

Bulk Electric System: A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system.

Bulk Transmission: A functional or voltage classification relating to the higher voltage portion of the transmission system, specifically, lines at or above a voltage level of 115 kV.

Bus: Shortened from the word busbar, meaning a node in an electrical network where one or more elements are connected together.

Capacitor Bank: A capacitor is an electrical device that provides reactive power to the system and is often used to compensate for reactive load and help support system voltage. A bank is a collection of one or more capacitors at a single location.

Capacity: The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.

Cascading: The uncontrolled successive loss of system elements triggered by an incident. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Circuit: A conductor or a system of conductors through which electric current flows.

Circuit Breaker: A switching device connected to the end of a transmission line capable of opening or closing the circuit in response to a command, usually from a relay.

Control Area: An electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to: (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load in the electric power system(s); (2) maintain, within the limits of Good Utility Practice, scheduled interchange with other Control Areas; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Contingency: The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Control Area Operator: An individual or organization responsible for controlling generation to maintain interchange schedule with other control areas and contributing to the frequency regulation of the interconnection. The control area is an electric system that is bounded by interconnection metering and telemetry.

Current (Electric): The rate of flow of electrons in an electrical conductor measured in Amperes.

Curtailability: The right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

Demand: The rate at which electric energy is delivered to consumers or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Also see “Load.”

DC: Direct current; current that is steady and does not change sinusoidally with time (see “AC”).

Dispatch Operator: Control of an integrated electric system involving operations such as assignment of levels of output to specific generating stations and other sources of supply; control of transmission lines, substations, and equipment; operation of principal interties and switching; and scheduling of energy transactions.

Distribution: For electricity, the function of distributing electric power using low voltage lines to retail customers.

Distribution Network: The portion of an electric system that is dedicated to delivering electric energy to an end user, at or below 69 kV. The distribution network consists primarily of low-voltage lines and transformers that “transport” electricity from the bulk power system to retail customers.

Disturbance: An unplanned event that produces an abnormal system condition.

Electrical Energy: The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).

Electric Utility: Person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy primarily for use by the public, and is defined as a utility under the statutes and rules by which it is regulated. An electric utility can be investor-owned, cooperatively owned, or government-owned (by a federal agency, crown corporation, State, provincial government, municipal government, and public power district).

Element: Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Energy Emergency: A condition when a system or power pool does not have adequate energy resources (including water for hydro units) to supply its customers’ expected energy requirements.

Emergency: Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system.

Emergency Voltage Limits: The operating voltage range on the interconnected systems that is acceptable for the time, sufficient for system adjustments to be made following a facility outage or system disturbance.

EMS: An energy management system is a computer control system used by electric utility dispatchers to monitor the real time performance of various elements of an electric system and to control generation and transmission facilities.

Fault: A fault usually means a short circuit, but more generally it refers to some abnormal system condition. Faults are often random events.

Federal Energy Regulatory Commission (FERC): Independent Federal agency that, among other responsibilities, regulates the transmission and wholesale sales of electricity in interstate commerce.

Flashover: A plasma arc initiated by some event such as lightning. Its effect is a short circuit on the network.

Flowgate: A single or group of transmission elements intended to model MW flow impact relating to transmission limitations and transmission service usage.

Forced Outage: The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Frequency: The number of complete alternations or cycles per second of an alternating current, measured in Hertz. The standard frequency in the

United States is 60 Hz. In some other countries the standard is 50 Hz.

Frequency Deviation or Error: A departure from scheduled frequency; the difference between actual system frequency and the scheduled system frequency.

Frequency Regulation: The ability of a Control Area to assist the interconnected system in maintaining scheduled frequency. This assistance can include both turbine governor response and automatic generation control.

Frequency Swings: Constant changes in frequency from its nominal or steady-state value.

Generation (Electricity): The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt hours (kWh) or megawatt hours (MWh).

Generator: Generally, an electromechanical device used to convert mechanical power to electrical power.

Grid: An electrical transmission and/or distribution network.

Grid Protection Scheme: Protection equipment for an electric power system, consisting of circuit breakers, certain equipment for measuring electrical quantities (e.g., current and voltage sensors) and devices called relays. Each relay is designed to protect the piece of equipment it has been assigned from damage. The basic philosophy in protection system design is that any equipment that is threatened with damage by a sustained fault is to be automatically taken out of service.

Ground: A conducting connection between an electrical circuit or device and the earth. A ground may be intentional, as in the case of a safety ground, or accidental, which may result in high overcurrents.

Imbalance: A condition where the generation and interchange schedules do not match demand.

Impedance: The total effects of a circuit that oppose the flow of an alternating current consisting of inductance, capacitance, and resistance. It can be quantified in the units of ohms.

Independent System Operator (ISO): An organization responsible for the reliable operation of the power grid under its purview and for providing open transmission access to all market participants on a nondiscriminatory basis. An ISO is usually not-for-profit and can advise utilities within its territory on transmission expansion and maintenance but does not have the responsibility to carry out the functions.

Interchange: Electric power or energy that flows across tie-lines from one entity to another, whether scheduled or inadvertent.

Interconnected System: A system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

Interconnection: When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT (Texas), Québec, and Alaska. When not capitalized, the facilities that connect two systems or Control Areas. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a Control Area or system.

Interface: The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.

ISAC: Information Sharing and Analysis Centers (ISACs) are designed by the private sector and serve as a mechanism for gathering, analyzing, appropriately sanitizing and disseminating private sector information. These centers could also gather, analyze, and disseminate information from Government for further distribution to the private sector. ISACs also are expected to share important information about vulnerabilities, threats, intrusions, and anomalies, but do not interfere with direct information exchanges between companies and the Government.

Island: A portion of a power system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system elements.

Kilovar (kVAr): Unit of alternating current reactive power equal to 1,000 VArs.

Kilovolt (kV): Unit of electrical potential equal to 1,000 Volts.

Kilovolt-Amperes (kVA): Unit of apparent power equal to 1,000 volt amperes. Here, apparent power is in contrast to real power. On AC systems the voltage and current will not be in phase if reactive power is being transmitted.

Kilowatthour (kWh): Unit of energy equaling one thousand watthours, or one kilowatt used over one hour. This is the normal quantity used for metering and billing electricity customers. The retail price for a kWh varies from approximately 4 cents to 15 cents. At a 100% conversion efficiency, one kWh is equivalent to about 4 fluid ounces of gasoline, 3/16 pound of liquid petroleum, 3 cubic feet of natural gas, or 1/4 pound of coal.

Line Trip: Refers to the automatic opening of the conducting path provided by a transmission line by the circuit breakers. These openings or "trips" are to protect the transmission line during faulted conditions.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers. See "Demand."

Load Shedding: The process of deliberately removing (either manually or automatically) preselected customer demand from a power system in response to an abnormal condition, to maintain the integrity of the system and minimize overall customer outages.

Lockout: A state of a transmission line following breaker operations where the condition detected by the protective relaying was not eliminated by temporarily opening and reclosing the line, possibly several times. In this state, the circuit breakers cannot generally be reclosed without resetting a lockout device.

Market Participant: An entity participating in the energy marketplace by buying/selling transmission rights, energy, or ancillary services into, out of, or through an ISO-controlled grid.

Megawatthour (MWh): One million watthours.

Metered Value: A measured electrical quantity that may be observed through telemetering, supervisory control and data acquisition (SCADA), or other means.

Metering: The methods of applying devices that measure and register the amount and direction of electrical quantities with respect to time.

NERC Interregional Security Network (ISN): A communications network used to exchange electric system operating parameters in near real time among those responsible for reliable operations of the electric system. The ISN provides timely and accurate data and information exchange among reliability coordinators and other system operators. The ISN, which operates over the frame relay NERCnet system, is a private Intranet that is capable of handling additional applications between participants.

Normal (Precontingency) Operating Procedures: Operating procedures that are normally invoked by the system operator to alleviate potential facility overloads or other potential system problems in anticipation of a contingency.

Normal Voltage Limits: The operating voltage range on the interconnected systems that is acceptable on a sustained basis.

North American Electric Reliability Council (NERC): A not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of nine Regional Reliability Councils and one Affiliate, whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The members of these Councils are from all segments of the electricity supply industry: investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers. The NERC Regions are: East Central Area Reliability Coordination Agreement (ECAR); Electric Reliability Council of Texas (ERCOT); Mid-Atlantic Area Council (MAAC); Mid-America Interconnected Network (MAIN); Mid-Continent Area Power Pool (MAPP); Northeast Power Coordinating Council (NPCC); Southeastern Electric Reliability Council (SERC); Southwest Power Pool (SPP); Western Systems Coordinating Council (WSCC); and Alaskan Systems Coordination Council (ASCC, Affiliate).

OASIS: Open Access Same Time Information Service (OASIS), developed by the Electric Power Research Institute, is designed to facilitate open access by providing users with access to information on transmission services and availability, plus facilities for transactions.

Operating Criteria: The fundamental principles of reliable interconnected systems operation, adopted by NERC.

Operating Guides: Operating practices that a Control Area or systems functioning as part of a Control Area may wish to consider. The application of Guides is optional and may vary among Control Areas to accommodate local conditions and individual system requirements.

Operating Policies: The doctrine developed for interconnected systems operation. This doctrine consists of Criteria, Standards, Requirements, Guides, and instructions, which apply to all Control Areas.

Operating Procedures: A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Operating Requirements: Obligations of a Control Area and systems functioning as part of a Control Area.

Operating Security Limit: The value of a system operating parameter (e.g. total power transfer across an interface) that satisfies the most limiting of prescribed pre- and post-contingency operating criteria as determined by equipment loading capability and acceptable stability and voltage conditions. It is the operating limit to be observed so that the transmission system will remain reliable even if the worst contingency occurs.

Operating Standards: The obligations of a Control Area and systems functioning as part of a Control Area that are measurable. An Operating Standard may specify monitoring and surveys for compliance.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Planning Guides: Good planning practices and considerations that Regions, subregions, power pools, or individual systems should follow. The application of Planning Guides may vary to match local conditions and individual system requirements.

Planning Policies: The framework for the reliability of interconnected bulk electric supply in terms of responsibilities for the development of and conformance to NERC Planning Principles and Guides and Regional planning criteria or guides, and NERC and Regional issues resolution processes. NERC Planning Procedures, Principles, and Guides emanate from the Planning Policies.

Planning Principles: The fundamental characteristics of reliable interconnected bulk electric systems and the tenets for planning them.

Planning Procedures: An explanation of how the Planning Policies are addressed and implemented by the NERC Engineering Committee, its subgroups, and the Regional Councils to achieve bulk electric system reliability.

Post-contingency Operating Procedures: Operating procedures that may be invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred.

Protective Relay: A device designed to detect abnormal system conditions, such as electrical shorts on the electric system or within generating plants, and initiate the operation of circuit breakers or other control equipment.

Power/Phase Angle: The angular relationship between an AC (sinusoidal) voltage across a circuit element and the AC (sinusoidal) current through it. The real power that can flow is related to this angle.

Power: See "Real Power."

Power Flow: See "Current."

Rate: The authorized charges per unite or level of consumption for a specified time period for any of the classes of utility services provided to a customer.

Rating: The operational limits of an electric system, facility, or element under a set of specified conditions.

Reactive Power: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr), and is the mathematical product of voltage and current consumed by reactive loads. Examples of reactive loads include capacitors and inductors. These types of loads, when connected to an ac voltage source, will draw current, but because the current is 90 degrees out of phase with the applied voltage, they actually consume no real power.

Readiness: The extent to which an organizational entity is prepared to meet the functional requirements set by NERC or its regional council for entities of that type or class.

Real Power: Also known as "active power." The rate at which work is performed or that energy is transferred, usually expressed in kilowatts (kW) or megawatts (MW). The terms "active power" or "real power" are often used in place of the term power alone to differentiate it from reactive power.

Real-Time Operations: The instantaneous operations of a power system as opposed to those operations that are simulated.

Regional Reliability Council: One of ten Electric Reliability Councils that form the North American Electric Reliability Council (NERC).

Regional Transmission Operator (RTO): An organization that is independent from all generation and power marketing interests and has exclusive responsibility for electric transmission grid operations, short-term electric reliability, and transmission services within a multi-State region. To achieve those objectives, the RTO manages transmission facilities owned by different companies and encompassing one, large, contiguous geographic area.

Regulations: Rules issued by regulatory authorities to implement laws passed by legislative bodies.

Relay: A device that controls the opening and subsequent reclosing of circuit breakers. Relays take measurements from local current and voltage transformers, and from communication channels connected to the remote end of the lines. A relay output trip signal is sent to circuit breakers when needed.

Relay Setting: The parameters that determine when a protective relay will initiate operation of circuit breakers or other control equipment.

Reliability: The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system, Adequacy and Security.

Reliability Coordinator: An individual or organization responsible for the safe and reliable operation of the interconnected transmission system for their defined area, in accordance with NERC reliability standards, regional criteria, and subregional criteria and practices. This entity facilitates the sharing of data and information about the status of the Control Areas for which it is responsible, establishes a security policy for these Control Areas and their interconnections, and coordinates emergency operating procedures that rely on common operating terminology, criteria, and standards.

Resistance: The characteristic of materials to restrict the flow of current in an electric circuit. Resistance is inherent in any electric wire, including those used for the transmission of electric power. Resistance in the wire is responsible for heating the wire as current flows through it and the subsequent power loss due to that heating.

Restoration: The process of returning generators and transmission system elements and restoring load following an outage on the electric system.

Right-of-Way (ROW) Maintenance: Activities by utilities to maintain electrical clearances along transmission or distribution lines.

Safe Limits: System limits on quantities such as voltage or power flows such that if the system is operated within these limits it is secure and reliable.

SCADA: Supervisory Control and Data Acquisition system; a system of remote control and telemetry used to monitor and control the electric system.

Schedule: An agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the contracting parties and the Control Area(s) involved in the transaction.

Scheduling Coordinator: An entity certified by an ISO or RTO for the purpose of undertaking scheduling functions.

Seams: The boundaries between adjacent electricity-related organizations. Differences in regulatory requirements or operating practices may create "seams problems."

Security: The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Security Coordinator: An individual or organization that provides the security assessment and emergency operations coordination for a group of Control Areas.

Short Circuit: A low resistance connection unintentionally made between points of an electrical circuit, which may result in current flow far above normal levels.

Shunt Capacitor Bank: Shunt capacitors are capacitors connected from the power system to an electrical ground. They are used to supply kilovars (reactive power) to the system at the point where they are connected. A shunt capacitor bank is a group of shunt capacitors.

Single Contingency: The sudden, unexpected failure or outage of a system facility(s) or element(s) (generating unit, transmission line, transformer, etc.). Elements removed from service as part of the operation of a remedial action scheme are considered part of a single contingency.

Special Protection System: An 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.

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Stability Limit: The maximum power flow possible through a particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.

State Estimator: Computer software that takes redundant measurements of quantities related to system state as input and provides an estimate of the system state (bus voltage phasors). It is used to confirm that the monitored electric power system is operating in a secure state by simulating the system both at the present time and one step ahead, for a particular network topology and loading condition. With the use of a state estimator and its associated contingency analysis software, system operators can review each critical contingency to determine whether each possible future state is within reliability limits.

Station: A node in an electrical network where one or more elements are connected. Examples include generating stations and substations.

Storage: Energy transferred form one entity to another entity that has the ability to conserve the energy (i.e., stored as water in a reservoir, coal in a pile, etc.) with the intent that the energy will be returned at a time when such energy is more useable to the original supplying entity.

Substation: Facility equipment that switches, changes, or regulates electric voltage.

Subtransmission: A functional or voltage classification relating to lines at voltage levels between 69kV and 115kV.

Supervisory Control and Data Acquisition (SCADA): See SCADA.

Surge: A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.

Surge Impedance Loading: The maximum amount of real power that can flow down a lossless transmission line such that the line does not require any VArs to support the flow.

Switching Station: Facility equipment used to tie together two or more electric circuits through switches. The switches are selectively arranged to permit a circuit to be disconnected, or to change the electric connection between the circuits.

Synchronize: The process of connecting two previously separated alternating current apparatuses after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).

System: An interconnected combination of generation, transmission, and distribution components comprising an electric utility and independent power producer(s) (IPP), or group of utilities and IPP(s).

System Operator: An individual at an electric system control center whose responsibility it is to monitor and control that electric system in real time.

System Reliability: A measure of an electric system's ability to deliver uninterrupted service at the proper voltage and frequency.

Thermal Limit: A power flow limit based on the possibility of damage by heat. Heating is caused by the electrical losses which are proportional to the square of the *real power* flow. More precisely, a thermal limit restricts the sum of the squares of *real* and *reactive power*.

Tie-line: The physical connection (e.g. transmission lines, transformers, switch gear, etc.) between two electric systems that permits the transfer of electric energy in one or both directions.

Time Error: An accumulated time difference between Control Area system time and the time standard. Time error is caused by a deviation in Interconnection frequency from 60.0 Hertz.

Time Error Correction: An offset to the Interconnection's scheduled frequency to correct for the time error accumulated on electric clocks.

Transactions: Sales of bulk power via the transmission grid.

Transfer Limit: The maximum amount of power that can be transferred in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions.

Transformer: A device that operates on magnetic principles to increase (step up) or decrease (step down) voltage.

Transient Stability: The ability of an electric system to maintain synchronism between its parts when subjected to a disturbance and to regain a state of equilibrium following that disturbance.

Transmission: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Loading Relief (TLR): A procedure used to manage congestion on the electric transmission system.

Transmission Margin: The difference between the maximum power flow a transmission line can handle and the amount that is currently flowing on the line.

Transmission Operator: NERC-certified party responsible for monitoring and assessing local reliability conditions, who operates the transmission facilities, and who executes switching orders in support of the Reliability Authority.

Transmission Overload: A state where a transmission line has exceeded either a normal or emergency rating of the electric conductor.

Transmission Owner (TO) or Transmission Provider: Any utility that owns, operates, or controls facilities used for the transmission of electric energy.

Trip: The opening of a circuit breaker or breakers on an electric system, normally to electrically isolate a particular element of the system to prevent it from being damaged by fault current or other potentially damaging conditions. See “Line Trip” for example.

Voltage: The electrical force, or “pressure,” that causes current to flow in a circuit, measured in Volts.

Voltage Collapse (decay): An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage Collapse may result in outage of system elements and may include interruption in service to customers.

Voltage Control: The control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

Voltage Limits: A hard limit above or below which is an undesirable operating condition. Normal limits are between 95 and 105 percent of the nominal voltage at the bus under discussion.

Voltage Reduction: A procedure designed to deliberately lower the voltage at a bus. It is often used as a means to reduce demand by lowering the customer’s voltage.

Voltage Stability: The condition of an electric system in which the sustained voltage level is controllable and within predetermined limits.

Watthour (Wh): A unit of measure of electrical energy equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Appendix G

Transmittal Letters from the Three Working Groups

Mr. James W. Glotfelty
Director, Office of Electric Transmission
and Distribution
U.S. Department of Energy
1000 Independence Avenue SW
Washington, DC 20585

Dr. Nawal Kamel
Special Assistant to the Deputy Minister
Natural Resources Canada
580 Booth Street
Ottawa, ON
K1A 0E4

Dear Mr. Glotfelty and Dr. Kamel:

Enclosed is the Final Report of the Electric System Working Group (ESWG) supporting the United States - Canada Power System Outage Task Force.

This report presents the results of an intensive and thorough investigation by a bi-national team into the causes of the blackout that occurred on August 14, 2003, and recommendations to prevent and reduce the scope of future blackouts. We believe that systematic implementation of these recommendations is critical to maintaining the reliability of bulk power supplies in North America.

The report was written largely by the three co-chairs of the Electric System Working Group (David Meyer, Alison Silverstein, and Tom Rusnov), who also co-chaired the Task Force's Electric System Investigation. They did so with the benefit of extensive input and assistance from many members of the investigation team. Other members of the ESWG reviewed the report in draft and provided valuable suggestions for its improvement. Those members join us in this submittal and have signed on the following page.

Sincerely,

David H. Meyer

David H. Meyer
Senior Advisor
U.S. Department
of Energy
Co-Chair, Electric
System Working Group

Thomas Rusnov
Senior Advisor
Natural Resources
Canada
Co-Chair, Electric
System Working Group

alison silverstein

Alison Silverstein
Senior Energy Policy Advisor
to the Chairman
Federal Energy Regulatory
Commission
Co-Chair, Electric
System Working Group

David Barrie
Senior Vice President
Asset Management
Hydro One Inc.

David Burpee, Director,
Renewable and Electrical Energy Division
Natural Resources Canada

For Donald W. Downes

Donald Downes, Chairman
Connecticut Department of
Public Utility Control

Joseph Eto, Staff Scientist
Lawrence Berkeley National Laboratory
(U.S.), and Consortium for Electric
Reliability Solutions

Jeanne Fox, President
New Jersey Board of Public Utilities

H. Kenneth Haase
Senior Vice President, Transmission
New York Power Authority

J. Peter Lark, Chairman
Michigan Public Service Commission

Blaine Loper, Senior Engineer
Pennsylvania Public Utility Commission

David McFadden
Chair, National Energy and Infrastructure
Industry Group
Gowlings, Lafleur, Henderson LLP
Ontario

David O'Brien, Commissioner
Vermont Department of Public Service

David O'Connor, Commissioner
Div. of Energy Resources
Massachusetts Office of Consumer Affairs
And Business Regulation

Alan Schriber, Chairman
Ohio Public Utilities Commission

Gene Whitney, Policy Analyst
National Science and Technology Council
U.S. Office of Science and Technology
Policy, Executive Office of the President

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

CHAIRMAN

Canadian Nuclear Safety Commission
President and Chief Executive Officer

Commission canadienne de sûreté nucléaire
Présidente et première dirigeante

February 27, 2004

Mr. James Glotfelty
Director, Office of Electric
Transmission and Distribution
U.S. Department of Energy
1000 Independence Ave., Suite 7B-222
Washington, DC 20585

Dr. Nawal Kamel
Special Assistant to the Deputy Minister
Natural Resources Canada
580 Booth Street
Ottawa, ON
K1A 0E4

Dear Mr. Glotfelty and Dr. Kamel:

Enclosed for incorporation into the Task Force report are revisions to the Interim Report and possible recommendations submitted for consideration by the Nuclear Working Group supporting the United States - Canada Joint Power System Outage Task Force. The members of the Nuclear Working Group join us in this submittal and have signed on the attached pages.

Please provide any comments related to the Canadian nuclear plants to either Mr. Pat Hawley (613-947-3992; hawleyp@cnsc-ccsn.gc.ca) or Mr. Mark Dallaire (613-947-0957; dallairem@cnsc-ccsn.gc.ca). Comments on the U.S. nuclear plants should be directed to either Mr. Cornelius Holden (301-415-3036; cfh@nrc.gov) or Mr. John Boska (301-415-2901; jpb1@nrc.gov).

Sincerely,

Nils J. Diaz
Chairman
U.S. Nuclear Regulatory Commission
U.S. Co-chair, Nuclear Working Group

Linda J. Keen
President and Chief Executive Officer
Canadian Nuclear Safety Commission
Canadian Co-chair, Nuclear Working Group

Enclosures: Nuclear Working Group Signature Pages (2)
Nuclear Working Group Final Report

cc w/encls: Mr. Ian Grant
Director General, Reactor Power Regulation
Canadian Nuclear Safety Commission

Mr. Samuel J. Collins
Deputy Executive Director, Reactor Programs
U.S. Nuclear Regulatory Commission

The members of the Nuclear Working Group hereby submit this report as input to the United States - Canada Joint Power System Outage Task Force:

Nils J. Diaz, Chairman
U.S. Nuclear Regulatory Commission
Co-chair, Nuclear Working Group

Samuel J. Collins, Deputy Executive Director for Reactor Programs
U.S. Nuclear Regulatory Commission

William D. Magwood, IV, Director, Office of Nuclear Energy, Science and Technology
U.S. Department of Energy

Edward Wilds, Bureau of Air Management, Department of Environmental Protection (Connecticut)

David O'Connor, Commissioner, Division of Energy Resources, Office of Consumer Affairs and Business Regulation (Massachusetts)

J. Peter Lark, Chairman, Public Service Commission (Michigan)

Frederick F. Butler, Commissioner, New Jersey Board of Public Utilities (New Jersey)

Paul Eddy, Power Systems Operations Specialist, Public Service Commission (New York)

Dr. G. Ivan Maldonado, Associate Professor, Mechanical, Industrial and Nuclear Engineering; University of Cincinnati (Ohio)

David J. Allard, CHP, Director, Bureau of Radiation Protection, Department of Environmental Protection (Pennsylvania)

David O'Brien, Commissioner
Department of Public Service (Vermont)

The members of the Nuclear Working Group hereby submit this report as input to the United States - Canada Joint Power System Outage Task Force:

Linda J. Keen
President and Chief Executive Officer
Canadian Nuclear Safety Commission
Co-chair, Nuclear Working Group

James Blyth
Director-General, Directorate of Nuclear Substance Regulation
Canadian Nuclear Safety Commission

Ken Pereira
Vice-President, Operations Branch
Canadian Nuclear Safety Commission

Dr. Robert Morrison
Senior Advisor to the Deputy Minister
Natural Resources Canada

Duncan Hawthorne
Chief Executive Officer
Bruce Power
(Representing the Province of Ontario)

Mr. James W. Glotfelty
Director, Office of Electric Transmission
and Distribution
U.S. Department of Energy
1000 Independence Avenue SW
Washington, DC 20585

Dr. Nawal Kamel
Special Assistant to the Deputy Minister
Natural Resources Canada
580 Booth Street
Ottawa, ON
K1A 0E4

Dear Mr. Glotfelty and Dr. Kamel:

Enclosed is the Final Report of the Security Working Group (SWG) supporting the United States - Canada Power System Outage Task Force.

The SWG Final Report presents the results of the Working Group`s analysis of the security aspects of the power outage that occurred on August 14, 2003 and provides recommendations for Task Force consideration on security-related issues in the electricity sector. This report comprises input from public sector, private sector, and academic members of the SWG, with important assistance from many members of the Task Force's investigative team. As co-chairs of the Security Working Group, we represent all members of the SWG in this submittal and have signed below.

Sincerely,

Bob Liscouski
Assistant Secretary for
Infrastructure Protection,
U.S. Department of Homeland Security
Co-Chair, SWG

William J.S. Elliott
Assistant Secretary to the Cabinet,
Security and Intelligence,
Privy Council Office
Government of Canada
Co-Chair, SWG

Attachment 1:

U.S.-Canada Power System Outage Task Force SWG Steering Committee members:

Bob Liscouski, Assistant Secretary for Infrastructure Protection, Department of Homeland Security (U.S. Government) (Co-Chair)

William J.S. Elliott, Assistant Secretary to the Cabinet, Security and Intelligence, Privy Council Office (Government of Canada) (Co-Chair)

U.S. Members

Andy Purdy, Deputy Director, National Cyber Security Division, Department of Homeland Security

Hal Hendershot, Acting Section Chief, Computer Intrusion Section, FBI

Steve Schmidt, Section Chief, Special Technologies and Applications, FBI

Kevin Kolevar, Senior Policy Advisor to the Secretary, DoE

Simon Szykman, Senior Policy Analyst, U.S. Office of Science &Technology Policy, White House

Vincent DeRosa, Deputy Commissioner, Director of Homeland Security (Connecticut)

Richard Swensen, Under-Secretary, Office of Public Safety and Homeland Security (Massachusetts)

Colonel Michael C. McDaniel (Michigan)

Sid Caspersen, Director, Office of Counter-Terrorism (New Jersey)

James McMahon, Senior Advisor (New York)

John Overly, Executive Director, Division of Homeland Security (Ohio)

Arthur Stephens, Deputy Secretary for Information Technology, (Pennsylvania)

Kerry L. Sleeper, Commissioner, Public Safety (Vermont)

Canada Members

James Harlick, Assistant Deputy Minister, Office of Critical Infrastructure Protection and Emergency Preparedness

Michael Devaney, Deputy Chief, Information Technology Security Communications Security Establishment

Peter MacAulay, Officer, Technological Crime Branch of the Royal Canadian Mounted Police

Gary Anderson, Chief, Counter-Intelligence – Global, Canadian Security Intelligence Service

Dr. James Young, Commissioner of Public Security, Ontario Ministry of Public Safety and Security

Exhibit G-2

2008 NERC Real-Time Tools Best Practices Task Force Report

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Real-Time Tools Survey Analysis and Recommendations

Final Report

March 13, 2008

Prepared by the

Real-Time Tools Best Practices Task Force

TABLE OF CONTENTS

Acknowledgments

Development of the Real-Time Tools Survey and preparation of this report between January 2004 and January 2007 would not have been possible without the contributions of many individuals working in electric power industry and for U.S. government agencies, energy companies, and regulatory organizations.

The authors wish to thank the following organizations and individuals in particular:

- The U.S. Department of Energy — Office of Electricity Delivery and Energy Reliability for the financial support to complete this work.

- Thanh Luong of the Federal Energy Regulatory Commission (FERC) for current information about FERC activities.

- Chris Bolduc of Lawrence Berkeley National Laboratory for the hardware and software to conduct the Real-Time Tools Survey.

- Steve Lee of the Electric Power Research Institute (EPRI) for guidance regarding survey development.

- Joe Eto of Lawrence Berkeley National Laboratory for his wisdom and guidance throughout the survey and report preparation process. The authors express special thanks for his ability to quickly identify and supply resources that were critical to completion of this report.

- Editors Nan Wishner and Moya Melody for the many hours they spent organizing this report into a single fluid document.

The North American Electric Reliability Corporation (NERC) thanks the members of the Real-Time Tools Best Practices Task Force (RTBPTF) for their work in developing the Real-Time Tools Survey and writing this report. NERC also acknowledges the companies for which the RTBPTF members work, for allowing the members the time necessary to complete the task force's scope of work:

Jack Kerr — Chairman, Real-Time Tools Best Practices Task Force
Dominion Virginia Power

Ed Batalla — Vice-chairman, Real-Time Tools Best Practices Task Force
Florida Power & Light Co.

Robert Kingsmore
Duke Energy Corporation

James Hartwell
Northeast Power Coordinating Council

Kenneth Thomas, Darryl G. Schrift, Jr.
PJM Interconnection, LLC

Gary Bullock
Tennessee Valley Authority

John Dumas, Tim Mortensen
Electric Reliability Council of Texas

Ed Germain
New England Independent System Operator

Alan Martin
Southern Company Services, Inc.

Bert Bressers
Southwest Power Pool

Kevin Sherd
Midwest Independent System Operator, Inc.

Grant McDonald, Rich Fetsick
Allegheny Power Systems

Vinit Gupta
Entergy

Note that the views and opinions expressed in this report are those of the contributing individuals and do not necessarily represent the views of their companies.

The authors also acknowledge the contributions of NERC staff:

- Don Benjamin helped inspire the original concept of surveying industry practices by facilitating the first RTBPTF meeting following the August 14, 2003 blackout.

- Jeff Norman and Larry Kezele coordinated the efforts of each contributor to complete the survey and assemble the final report and recommendations.

- Brian Nolan and the NERC Information Technology staff provided online access to the survey.

Finally, RTBPTF thanks all of the organizations whose responses to the survey allowed the task force to understand how real-time tools are used throughout the electric power industry in the wake of the August 14, 2003 blackout. Those organizations are listed in Appendix B, Survey Participation.

Acronyms and Abbreviations

ACE	area control error
AEC	Alabama Electric Cooperative, Inc.
AECI	Associated Electric Cooperative, Inc.
AEP	American Electric Power
AESO	Alberta Electric System Operator
AGC	automatic generation control
AP	Allegheny Power
ATC	American Transmission Company or available transfer capability
AVR	automatic voltage regulator
BA	balancing authority
BOT	Board of Trustees (NERC)
BPAT `	Bonneville Power Administration
CFE	Comision Federal De Electricidad
CFLA	critical facility loading assessment
CIN	Cinergy Corporation
CLEC	Cleco Corporation
CMRC	California Mexico Reliability Coordinator
CSWS	AES — Central and Southwest
DCS	disturbance control standard
DEWG	Data Exchange Working Group
DMS	distribution management system
DOC	distribution operations center
DOPD	PUD #1 of Douglas County
DPL	Dayton Power and Light
DSA	dynamic stability assessment
DSM	demand-side management
DSMON	data set monitor
DTS	dispatcher training simulator
DUK	Duke Energy Corporation
ECAR	East Central Area Reliability Council
EDT	Eastern Daylight Time
EEA	energy emergency alert
EES	Entergy Services, Inc.
EMS	energy management system
EPAct	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ERCO	ERCOT ISO
ERO	electricity reliability organization
FE	FirstEnergy
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FPL	Florida Power and Light
FRCC	Florida Reliability Coordinating Council

FTC	facilitated transaction checkout
FTE	full time equivalent
GCPD	Grant County Public Utility District
GMS	geo-magnetic storm
GSU	generator step up
HMI	human-machine interface
HQT	Hydro-Quebec TransEnergie (HQT)
ICAP	Installed Capacity
ICCP	Inter-control center communications protocol
ID	identification
IDC	Interchange Distribution Calculator
IEEE	Institute of Electrical and Electronics Engineers
IMO	The Independent Electricity System Operator (IMO)
IPP	independent power producer
IROL	interconnected reliability operating limit
ISN	Inter-regional Security Network
ISO	independent system operator
ISO-NE	independent system operator New England
IT	information technology
ITC	International Transmission Company
kV	kilovolt
LES	Lincoln Electric System
LMP	locational marginal pricing
LODF	line outage distribution factor
LOOP	loss of offsite power
LTC	load top changer
MGE	Madison Gas and Electric Company
MISO	Midwest Independent System Operator
MVA	Megavoltamperes
Mvar	mega Var
MW	megawatt
NBSO	New Brunswick System Operator
NERC	North American Electric Reliability Corporation
NIPS	Northern Indiana Public Service Company
NMPC	Niagara Mohawk Power Corporation
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission
NTP	network topology processor
NWMT	NorthWestern Energy
NYIS	New York ISO
OC	Operating Committee (NERC)
OKGE	Oklahoma Gas and Electric
OPF	optimal power flow
ORS	Operating Reliability Subcommittee (NERC)
OTP	Otter Tail Power Company
PAR	phase-angle regulating

PCT	process control test
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PMU	phasor measurement unit
PNM	Public Service Company of New Mexico
PRD	production
PV	power/voltage (analysis)
QA	quality assurance
QV	reactive/voltage (analysis)
RAS	remedial action scheme
RC	reliability coordinator
RCWG	Reliability Coordinator Working Group
RDRC	Rocky Mountain — Desert Southwest Reliability Coordinator
RPU	Rochester Public Utilities
RRO	regional reliability organization
RTCAA	real-time contingency analysis availability
RTO	regional transmission organization
RTOP	regional transmission operator
RTU	remote terminal unit
RTBPTF	Real-Time Tools Best Practices Task Force
SAR	Standards Authorization Request
SC	Santee Cooper
SCADA	Supervisory Control and Data Acquisition
SCEG	South Carolina Electric and Gas Company
SEA	state estimator availability
SERC	SERC Reliability Corporation
SMD	solar magnetic disturbance
SMP	Southern Minnesota Municipal Power Agency
SOC	system operation center
SOCO	Southern Company Services, Inc.
SOL	system operating limit
SPC	Saskatchewan
SPS	Southwestern Public Service — Xcel
SPP	Southwest Power Pool
SPPC	Sierra Pacific Power Company
SPRM	City Utilities, Springfield, MO
SPS	special protection system
SRTM	study real-time maintenance
SVC	static Var compensator
SWPP	Southwest Power Pool
TAED	topology and analog error detection
TAL	City of Tallahassee
TOC	transmission operation center
TOP	transmission operator
TRS	trouble report system
TSIN	Transmission System Information Network
TT	thermal tracking

TVA	Tennessee Valley Authority
TTC	total transfer capability
TX	transformer
UFLS	under-frequency load-shed
UVLS	under-voltage load shed
VACAR	Virginia Carolinas (subregion of SERC)
var	volt ampere reactive
VEDI	Vectren Energy Delivery of Indiana
VSA	voltage stability analysis
VTWG	visualization tools working group
WAUW	Western Area Power Administration — Upper Great Plains Region
WEC	Wisconsin Energy Corporation
WPEL	Aquila, Inc.
WR	Westar

How to Read this Document

Because this document is long and full of survey findings, readers may find it helpful to start by skimming the **Table of Contents** to identify areas of particular interest and reviewing the **Executive Summary** for highlights of the main findings and recommendations. The table immediately following the Executive Summary lists of all of the report's recommendations.

Readers will find the in-depth overview presented in the **Introduction** helpful for understanding the interrelationships among the tools and practices covered in the report and the larger context for any particular topic of interest. The Introduction summarizes the history of Real-Time Tools Best Practices Task Force (RTBPTF), the task force's charge, the task force's comprehensive Real-Time Tools Survey of electric industry practices, the major findings and recommendations resulting from the analysis of the survey results, and proposals for next steps.

Readers interested in specific subjects will find it helpful, after reading the Introduction, to read the introductory sections on those subjects: **1.0, Real-Time Data Collection; 2.0, Reliability Tools for Situational Awareness; 3.0, Situational Awareness Practices; 4.0, Power System Models; 5.0, Support and Maintenance Tools**.

Following each introductory section are **specific subsections (1.1., 1.2, 1.3, 2.1, etc.)** that treat in detail the individual tools and practices investigated in this report. These sections define the tool, summarize the survey findings regarding it, and, if applicable, present recommendations related to the tool and its performance as well as noting areas for further research and analysis.

Readers interested in the details of where the industry should go next with real-time tools standards will find **Section 6.0, Next Steps** of interest.

Following the main text, **Appendices** describe the task force's survey development, participation, and analysis methodology as well as the Examples of Excellence discovered in the survey results. Aggregate survey responses are also available as pdfs at http://www.nerc.com/~filez/rtbptf.html.

Finally, a **Glossary** and an **Acronym** list are included to help readers manage the technical vocabulary of the document. The glossary will be especially useful for understanding the new technical terms and concepts the task force introduces in this report, including: "bulk electric system elements list," "critical applications monitoring," "critical equipment," "critical real-time tool," and "wide-area-view boundary."

Executive Summary

This report presents the findings and recommendations of the North American Electric Reliability Corporation (NERC) Real-Time Tools Best Practices Task Force (RTBPTF) regarding minimum acceptable capabilities and best practices for real-time tools necessary to ensure reliable electric system operation and reliability coordination.

RTBPTF's mission is primarily based on the U.S.-Canada Power System Outage Task Force findings that key causes of the August 14, 2003 northeast blackout included lack of situational awareness and inadequate reliability tools. That report also notes the need for visualization display systems to monitor system reliability.[1]

RTBPTF's recommendations result from an extensive, three-year process of fact-finding and analysis supported by the results of the Real-Time Tools Survey, the most comprehensive survey ever conducted of current electric industry practices.

Recommendations

RTBPTF makes major recommendations in three key areas to establish requirements that apply to reliability coordinators (RCs), transmission operators (TOPs), and other entities with similar responsibility:

1. Reliability Toolbox[2] — Require five real-time tools as well as performance and availability metrics and maintenance practices for each. The required tools are:

- Telemetry data systems
- Alarm tools
- Network topology processor
- State estimator
- Contingency analysis

2. Enhanced Operator Situational Awareness — Require standards and guidelines for situational awareness practices, including:

- Power-flow simulations
- Conservative operations plans
- Load-shed capability awareness
- Critical applications and facilities monitoring
- Visualization techniques

---

[1] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. (Referred to in the text of this document as the *Outage Task Force Final Blackout Report*.)

[2] The relationships among the required tools are illustrated in Figure 4 of the Introduction following this Executive Summary.

The task force also recommends that NERC:

3. Address Six Major Issues to enhance the effectiveness of real-time tools:

1) Definition of the bulk electric system
2) Definition of the wide-area-view boundary
3) Development of system models and standards for exchange of model information
4) Specification of acceptable reactive reserves
5) Determination of adequate load-shed capability
6) Provision of adequate funding and staffing for maintaining and upgrading real-time tools

In addition to the major recommendations listed above, the task force makes a number of other specific recommendations related to particular real-time tools, all of which are listed in Table ES-1.

Presentation of Recommendations

The recommendations in Table ES-1 are presented throughout this report as color coded text boxes in accordance with the following color scheme:

1. Blue – Recommendations for new or revised reliability standards
2. Green – Recommendations for operating guides
3. Red – Recommendations regarding areas requiring more analysis
4. Blue-Green – Recommendations to address issues to enhance the effectiveness of real-time operation

Real-Time Tools Survey

RTBPTF's findings and recommendations are firmly grounded in the results of the Real-Time Tools Survey, a more than 300-page, web-based document with nearly 2,000 questions on a broad scope of current industry practices and plans for using real-time tools. All 17 North American RCs participated in the survey along with an additional 42 TOPs and/or Balancing Authorities (BAs) (that are not also RCs), which represent about one-third of the total number of TOPs and BAs. Thus, the survey responses reflect the current status and practices of a significant and geographically diverse portion of the North American electric industry.[3]

Focus on Situational Awareness

In this report, RTBPTF focuses on real-time tools that support system operators' situational awareness, as called for in the *Outage Task Force Final Blackout*

[3] The geographic locations of the survey participants are shown in Figure 2 (for RCs) and Figure 3 (for TOPs and BAs) of the Introduction following this Executive Summary.

Report. Situational awareness, as RTBPTF understands it, means ensuring that accurate information on current system conditions, including the likely effects of future contingencies, is continuously available in a form that allows operators to quickly grasp and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations.

Next Steps

Much work lies ahead to implement the task force's recommendations for revised standards and operating guidelines to improve reliability through better real-time operating tools and practices and to conduct needed additional analyses. In the short term, RTBPTF proposes to finish work on the following activities, which will complete the remainder of the task force's assigned scope of work:

- Append recommendations for revised standards to the existing Standards Review Forms
- Provide technical support to the standards drafting teams
- Prioritize areas requiring more analysis
- Write high-level scopes for the analysis required

Following completion of these activities, RTBPTF will disband.

RTBPTF also recommends the following additional steps, which are outside the task force's assigned scope:

- The NERC Operating Reliability Subcommittee (ORS) should determine how operating guidelines are to be developed and maintained, and

- The NERC Operating Committee (OC) should consider asking the regional reliability organizations (RROs) to develop operating guidelines as "supplements" to the NERC standards.

Organization of this Report

The core, technical portion of this report is organized into five major sections that address the main subject areas of the Real-Time Tools Survey[4] and a sixth section that details the next steps toward implementing RTBPTF's recommendations:

Section 1.0, Real-Time Data Collection
Section 2.0, Reliability Tools for Situational Awareness
Section 3.0, Situational Awareness Practices

[4] The relationships among the tools and practices covered in Sections 1-5 of this report are illustrated in Figure 1 of the Introduction that follows this Executive Summary.

Section 4.0, Power System Modeling
Section 5.0, Support and Maintenance Tools
Section 6.0, Next Steps

Within each of the five major sections, a general introduction is followed by sections focusing on the main topic areas in that section. Each topical section is structured as follows:

- Definition of the specific topic
- Background on the specific topic
- Summary of Survey Findings on the specific topic
- Task Force Recommendations on the specific topic, if any, including:
    - Recommendations for New Reliability Standards
    - Recommendations for Operating Guidelines
    - Areas Requiring More Analysis
    - Examples of Excellence

A number of appendices address the Real-Time Tools Survey development (Appendix A), participation (Appendix B) and analysis (Appendix C), as well as related web links (Appendix D). Appendix E presents the Examples of Excellence in detail. A glossary and an acronym list are also included for the reader's convenience.

Summary of Recommendations

Number	*Recommendations Related to New Reliability Standards or New Requirements to Existing Standards*	Section Number	Page Number
S1	Mandate the following reliability tools as mandatory monitoring and analysis tools.		
	Alarm Tools	2.1	12
	Telemetry Data Systems	1.1	26
	Network Topology Processor	2.3	68
	State Estimator	2.5	106
	Contingency Analysis	2.6	137
S2	Compile and maintain a list of all bulk electric system elements within RC's area of responsibility.	1.1	34
S3	Add new requirements and measures pertaining to RC monitoring of the bulk electric system.	1.1	36
S4	Develop data-exchange standards.	1.2	59
S5	Develop data-availability standards and a process for trouble resolution and escalation.	1.2	61
S6	Develop a new weather data requirement related to situational awareness and real-time operational capabilities.	1.3	69
S7	Specify and measure minimum availability for alarm tools.	2.1	13
S8	Specify and measure minimum availability for network topology processor.	2.3	69
S9	Establish a uniform formal process to determine the "wide-area view boundary" and show boundary data/results.	2.2	38
S10	Develop compliance measures for verification of the usage of "wide-area overview display" visualization tools.	2.2	44
S11	Specify and measure minimum availability for state estimator, including a requirement for solution quality.	2.5	107

Number	*Recommendations Related to New Reliability Standards or New Requirements to Existing Standards*	Section Number	Page Number
S12	Specify and measure minimum availability for contingency analysis, including a requirement for solution quality.	2.6	138
S13	Specify criteria and develop measures for defining contingencies.	2.6	143
S14	Perform one-hour-ahead power-flow simulations to assess approaching SOL and IROL violations and corresponding measures.	2.8	158
S15	Provide real-time awareness of load-shed capability to address potential or actual IROL violations.	2.13	185
S16	Require BAs to monitor contingency reserves and calculate contingency reserves at a minimum periodicity of 10 seconds.	3.1	14
S17	Revise the current-day operations requirements to delineate specific, independent requirements for monitoring operating and reactive reserves.	3.1	14
S18	Establish document plans and procedures for conservative operations.	3.3	26
S19	Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes.	3.3	26
S20	Develop formal operating guides (mitigation plans) and measures for each IROL and any SOL or other conditions having a potential impact on reliability.	3.4	37
S21	Review and update operating guides (mitigation plans) when day-ahead or current day studies indicate the potential need to implement an operating guide.	3.4	38
S22	Provide temporary operating guides (mitigation plans) with control actions for situations that could affect reliability but that have not been identified previously.	3.4	38
S23	Develop joint operating guides (mitigation plans) for situations that could require more than one RC or more than one TOP to execute actions.	3.4	39

Number	*Recommendations Related to New Reliability Standards or New Requirements to Existing Standards*	Section Number	Page Number
S24	Develop a formal procedure to document the processes for developing, reviewing, and updating operating guides (mitigation plans).	3.4	39
S25	Incorporate verifiable and traceable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates when modifying operating guides (mitigation plans).	3.4	39
S26	Write operating guides (mitigation plans) in clear, unambiguous language, leaving nothing to interpretation.	3.4	40
S27	State the specific purpose of existence for each operating guide (mitigation plan).	3.4	40
S28	Summarize the specific situation assessment and address the method of performing the assessment in each operating guide (mitigation plan).	3.4	40
S29	Identify all appropriate preventive and remedial control actions in each operating guide (mitigation plan).	3.4	41
S30	Develop criteria in operating guides (mitigation plans) to support decisions regarding whether a specific control action should be taken.	3.4	41
S31	Incorporate on-line tools that utilize on-line data when operating guides (mitigation plans) require calculations.	3.4	41
S32	Make operating guides (mitigation plans) readily available via a quick-access method such as Web-based help, EMS display notes, or on-line help systems.	3.4	42
S33	Provide the location, real-time status, and MWs of load available to be shed.	3.5	49
S34	Establish documented procedures for the reassessment and re-posturing of the system following an event.	3.6	56
S35	Provide information to operators to maintain awareness of the availability and capability of the blackstart generators and transmission restoration paths.	3.7	64

Number	***Recommendations Related to New Reliability Standards or New Requirements to Existing Standards***	Section Number	Page Number
S36	Plan and coordinate scheduled outages of blackstart generators and transmission restoration paths.	3.7	65
S37	Maintain a Critical Equipment Monitoring Document to identify tools and procedures for monitoring critical equipment.	5.2	16
S38	Maintain event logs pertaining to critical equipment status for a period of one year.	5.2	16
S39	Maintain a Critical Equipment Maintenance and Testing Document identifying tools and procedures for maintenance, modification, and testing of critical equipment.	5.2	17
S40	Monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation.	5.3	24

Number	***Recommendations Related to New Operating Guidelines***	Section Number	Page Number
G1	Identify implementation strategies and specific algorithms for conditional alarming.	2.1	14
G2	Consider human factors, ergonomics and maintenance/support issues in implementing visualization tools.	2.2	52
G3	Develop a chronological outage/return summary in network topology processor for recreating events and aiding state estimator.	2.3	73
G4	Establish state estimator solution-quality metrics to ensure accurate data and other reliability analysis.	2.5	111
G5	Identify only existing controls modeled in contingency analysis and develop conservative contingency screening criteria.	2.6	145
G6	Perform one-hour ahead contingency analysis to identify potential post-contingent problems approaching in next hour.	2.8	159
G7	Use the study real-time maintenance application to reproduce real-time snapshots.	2.9	165
G8	Develop a list of the minimum set of items that should be included in the calculations for actual and required operating reserves.	3.1	15
G9	Provide written alarm response procedures via at least one quick access method such as Web-based help or on-line help system.	3.2	20
G10	Specify the system conditions for initiating conservative operations and action plans to follow during conservative operations.	3.3	27
G11	Communicate and coordinate with neighboring systems for reassessing and re-posturing a system following an event that places the system in an insecure or unstudied state.	3.6	58

Number	*Recommendations Related to New Operating Guidelines*	Section Number	Page Number
G12	Monitor and ensure operator awareness of current conditions of blackstart generators and status of transmission restoration paths.	3.7	66
G13	Establish a change management process for performing critical equipment maintenance, modification, and testing.	5.3	27
G14	Develop a notification process when critical equipment is unavailable and an analysis/resolution process for critical equipment failures.	5.3	27
G15	Develop a critical monitoring application that interfaces to alarm tools and logs all events related to the equipment failures.	5.3	28
G16	Develop a process for monitoring critical real-time tools including change notification, status update, and severity of a situation.	5.4	35

Number	***Recommendations Related to Areas Requiring Additional Analysis***	Section Number	Page Number
A1	Investigate the impact of time skew on state-estimator solution quality.	1.2	63
A2	Identify necessary fidelity and scope of real-time models and the extent of the requisite data-exchange sets.	1.2	64
A3	Study intelligent alarm processing capability for producing a single accurate view of system status.	2.1	15
A4	Conduct research to assess current technology and practices related to the use and application of visualization tools.	2.2	53
A5	Establish a Visualization Tools Working Group (VTWG) to foster and facilitate sharing of best practices.	2.2	54
A6	Identify minimum measurement observables, adequate redundancy, and critical measurements to improve state-estimator observability and solution quality.	2.5	116
A7	Establish a pilot program to collect data and build appropriate state estimator performance metrics.	2.5	118
A8	Evaluate capability of critical facility loading assessment application in providing a backup solution if contingency analysis or the state estimator is unavailable.	2.7	150
A9	Verify accuracy of one-hour power-flow and contingency analysis results and ability to detect a potential voltage collapse revealed by a failed power-flow solution.	2.8	160
A10	Obtain additional information on how the study real-time maintenance application is utilized to enhance debugging capability.	2.9	166
A11	Assess the voltage stability assessment (VSA) application to learn how the VSA can be enhanced to become more widely used.	2.10	171
A12	Assess the dynamic stability assessment (DSA) application to learn how the DSA can be enhanced to become more widely used.	2.11	175

A13	Analyze the need to define reactive power (Mvar) capacity requirement and use a Mvar assessment application.	2.12	179
A14	Research how emergency tools and visualization techniques are used in load shedding plans.	2.13	186
A15	Analyze the need to use tools for congestion management, voltage profiles, wind-energy forecast, and weather forecast.	2.14	192
A16	Investigate processes and procedures for internal system update and external data exchange, including CIM XML models.	4.2	60
A17	Investigate whether critical application monitor tools should be independent of the critical real-time tool being monitored.	5.4	36

Number	*Recommendations Related to Major Issues to be Addressed*	Section Number	Page Number
I1	Define what constitutes bulk electric system elements and parameters as they relate to existing standards.	1.1	27
I2	Define wide-area view boundary.	2.2	38
I3	Specify acceptable reactive reserves.	3.1	13
I4	Determine adequate load-shed capability.	3.5	48
I5	Develop system models and standards for exchange of model information.	4.2	61
I6	Provide adequate funding and staffing for maintaining and upgrading real-time tools.	6.0	2

Introduction

The North American Electric Reliability Corporation (NERC) Real-Time Tools Best Practices Task Force (RTBPTF) was formed in 2004 to identify the best practices for real-time reliability tools used to build and maintain real-time network models, perform state estimation and contingency analysis, and maintain situational awareness in accordance with NERC Reliability Standards. The task force was also instructed to develop guidelines for minimally acceptable capabilities for these critical reliability tools and to recommend specific requirements to be included in reliability standards for these tools.

This report presents RTBPTF's findings and recommendations, organized by individual tool or practice under the following five major headings:

- Real-Time Data Collection
- Reliability Tools for Situational Awareness
- Situational Awareness Practices
- Modeling Practices
- Support and Maintenance Tools

In total, RTBPTF recommends:

- 40 revisions to existing NERC standards;
- 16 operating guidelines; and
- 17 areas that require more analysis

In addition, RTBPTF has assembled 24 examples of excellence in the use of real-time tools.

RTBPTF's recommendations result from an extensive, three-year process of fact-finding and analysis based on the results of the Real-Time Tools Survey, the most comprehensive survey ever conducted on current electric industry practices.

The subsections of this Introduction describe:

- the history of RTBPTF's formation
- RTBPTF's scope of work
- the Real-Time Tools Survey
- RTPBTF's major findings
- criteria by which RTBPTF's recommendations were developed
- details of RTBPTF's major recommendations
- specific proposals for next steps in NERC's work on real-time tools

Background

RTBPTF's formation and scope of work resulted from investigation of the August 14, 2003 northeast blackout by the U.S. - Canada Power System Outage Task Force and by NERC.

The passage of the Energy Policy Act of 2005 (EPAct)[1] calling for mandatory reliability standards and publication of a Federal Energy Regulatory Commission (FERC) assessment of NERC's proposed mandatory reliability standards[2] also contributed to the task force's understanding of its charge.

Blackout Investigation

The timeline leading to RTBPTF's creation begins with a December 2003 U.S.-Canada Power System Outage Task Force technical conference, which produced a series of recommendations to prevent future blackouts. Two of the conference panel discussion topics, "Operating Tools" and "Reliability Coordination," inspired the initial draft of the scope of work that was ultimately assigned to RTBPTF.

In February 2004, not long after the Outage Task Force Conference, the NERC Board of Trustees (BOT) approved the NERC Steering Group's recommended actions to prevent and mitigate future blackouts.[3] BOT directed the NERC Operating Committee (OC) to carry out Recommendation 10, which states:

> The Operating Committee shall within one year evaluate the real-time operating tools necessary for reliable operation and reliability coordination, including backup capabilities. The Operating Committee is directed to report both minimum acceptable capabilities for critical reliability functions and a guide of best practices.

The supporting discussion for Recommendation 10 states that the evaluation should include consideration of the following:

- Modeling requirements, such as model size and fidelity, real and reactive load modeling, sensitivity analyses, accuracy analyses, validation, measurement observability, update procedures, and procedures for the timely exchange of modeling data

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[1]Energy Policy Act of 2005. Public Law 109–58. 42 USC 15801.
[2] Federal Energy Regulatory Commission. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. RM06-16-000. May 11, 2006. (Referred to in the text of this document as the *FERC Staff Assessment*.)
[3] North American Electric Reliability Corporation. 2004. *August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts.* February 10. (Referred to in the text of this document as the *NERC Blackout Report*.)

- State estimation requirements, such as periodicity of execution, monitoring external facilities, solution quality, topology error and measurement error detection, failure rates including times between failures, presentation of solution results including alarms, and troubleshooting procedures
- Real-time contingency analysis requirements, such as contingency definition, periodicity of execution, monitoring external facilities, solution quality, post-contingency automatic actions, failure rates including mean/maximum times between failures, reporting of results, presentation of solution results including alarms, and troubleshooting procedures including procedures for investigating unsolvable contingencies

Next, in April 2004, the U.S.-Canada Power System Outage Task Force issued its final report.[4] Recommendation 22 of the *Outage Task Force Final Blackout Report* supports NERC's Recommendation 10. Recommendation 22 reads as follows:

> Evaluate and adopt better real-time tools for operators and reliability coordinators.
>
> NERC's requirements of February 10, 2004, direct its Operating Committee to evaluate within one year the real-time operating tools necessary for reliable operation and reliability coordination, including backup capabilities. The committee's report is to address both minimum acceptable capabilities for critical reliability functions and a guide to best practices. The [U.S.-Canada Power System Outage] Task Force supports these requirements strongly. It recommends that NERC require the committee to:
>
> A. Give particular attention in its report to the development of guidance to control areas and reliability coordinators on the use of automated wide-area situation visualization display systems and the integrity of data used in those systems.
>
> B. Prepare its report in consultation with FERC, appropriate authorities in Canada, DOE [U.S. Department of Energy], and the regional councils. The report should also inform actions by FERC and Canadian government agencies to establish minimum

[4] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. (Referred to in the text of this document as the *Outage Task Force Final Blackout Report.*)

> functional requirements for control area operators and reliability coordinators.[5]

The *Outage Task Force Final Blackout Report* makes clear the relationship between reliability tools and electric system operator situational awareness and the role of both in causing the 2003 blackout; the report also emphasizes the need for a consistent means for operators to understand the status of the power grid outside their control areas:

> A principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools and backup capabilities. In addition, the failure of First Energy's control computers and alarm system contributed directly to the lack of situational awareness. Likewise, [the Midwest Independent System Operator's] MISO's incomplete tool set and the failure to supply its state estimator with correct system data on August 14 contributed to the lack of situational awareness. The need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations….
>
> The investigation of the August 14 blackout revealed that there has been no consistent means across the Eastern Interconnection to provide an understanding of the status of the power grid outside of a control area. Improved visibility of the status of the grid beyond an operator's own area of control would aid the operator in making adjustments in its operations to mitigate potential problems. The expanded view advocated above would also enable facilities to be more proactive in operations and contingency planning.

In response to Outage Task Force Recommendation 22 and NERC Recommendation 10, OC formed RTBPTF.

Mandatory Reliability Standards

As noted above, subsequent to RTBPTF's formation, passage of EPAct and publication of the *FERC Staff Assessment* of NERC's proposed mandatory reliability standards contributed to RTBPTF's understanding of its charge.

[5] Although the task force included a member from a regional council and a liaison from FERC, the consultation with "FERC, appropriate authorities in Canada, DOE, and the regional councils" to inform the development of minimum functional requirements, as envisioned in Recommendation 22, was supplanted by RTBPTF's efforts to make specific recommendations for new reliability standards.

EPAct authorized FERC to adopt mandatory reliability rules and to certify an Electricity Reliability Organization (ERO) to enforce them. Passage of EPAct made it clear that RTBPTF's recommendations for revisions to standards, if adopted, will become enforceable mandatory requirements.

In May 2006, FERC released its preliminary *Staff Assessment* of NERC's proposed mandatory reliability standards. On the topic of analysis tools in Standard IRO-002,[6] the assessment states: "[t]he standard does not have any Compliance Measures and Levels of Noncompliance and without such specificity, the ERO will not have norms that are specific enough to implement consistent and effective enforcement." This observation makes clear the need to establish performance measures for required real-time tools and practices.

On the topic of real-time monitoring in Standard TOP-006-0,[7] FERC staff states:

> [W]hile the requirements identify the data to be gathered, they fail to describe the tools necessary to turn that data into critical reliability parameters, e.g., system capability or contingency analysis, which are required to achieve situational awareness. Reliability Coordinators, Transmission Operators, and Balancing Authorities must be aware of the status of their respective systems, and such situational awareness cannot be obtained by viewing massive amounts of raw data. The standard does not contain any Measures to assess compliance with Requirements or Levels of Non-Compliance required for enforcement.

This analysis by FERC staff underscores the need to require real-time tools that present system status information in ways that operators can quickly grasp so that they can take action to correct system problems, and the need to define performance measures for standards.

RTBPTF Scope

NERC ORS and OC approved a scope of work for RTBPTF in summer 2004.[8] RTBPTF held its first meeting in September 2004 and revised the scope to add the term "situational awareness," the task of defining "best practices," and a

[6] "Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays."
[7] "To ensure critical reliability parameters are monitored in real-time."
[8] The initial draft of RTBPTF's scope of work had been presented for consideration at a joint meeting of the NERC ORS and the NERC Reliability Coordinator Working Group (RCWG) in January 2004 and was also submitted to the NERC Steering Group in response to their invitation for comments on their proposed *NERC Blackout Report.*

notation that there may be more than one best practice (see “Understanding RTBPTF’s Scope” below.) ORS accepted the revised scope in December 2004.

RTBPTF’s final scope reads as follows:

1. Define and explain what is meant by the term, “Best Practice,” in the context of this work scope.
2. Develop a focused survey (preferably web-based) for distribution to entities responsible for reliable operations to determine which tools those entities use to perform state estimation, perform real-time contingency analysis, and maintain situational awareness of their systems. The survey shall be designed to identify the methods and criteria these entities employ to build and maintain the necessary models and to execute and monitor the performance of the reliability tools.
3. Develop a survey of users of automated, wide-area visualization display technologies to determine guidelines for their application and the integrity of data displayed to the users.
4. Present an interim report to the ORS summarizing the results of the surveys and outlining the scope and timeline of the remaining work.
5. Conduct detailed interviews and on-site reviews of the entities identified by the survey as having the best practices in order to document how the best practices contribute to superior performance.
6. Present a report to the ORS with recommendations for specific methods, design criteria, and performance parameters and thresholds to serve as the basis for guidelines for minimally acceptable capabilities for real-time network modeling and the use and performance of network analysis tools and situational awareness tools.
7. Provide technical support for the development of new standards for real-time network models, network analysis tools, and situational awareness tools.

In performing the assigned tasks, RTBPTF shall:

1. Consider all aspects of model building and maintenance including, but not limited to, proper model size, model fidelity, real and reactive load modeling, sensitivity analyses, accuracy analyses, validation, measurement observability, update procedures, and procedures for the timely exchange of modeling data
2. Consider all aspects of state estimation including, but not limited to, periodicity of execution, monitoring external facilities, solution quality, topology error and measurement error detection, failure rates including

mean/max times between failures, presentation of solution results including alarms, and troubleshooting procedures

3. Consider all aspects of real-time contingency analysis including, but not limited to, contingency definition, periodicity of execution, monitoring external facilities, solution quality, post-contingency automatic actions, failure rates including mean/max times between failures, reporting of results, presentation of solution results including alarms, and troubleshooting procedures including procedures for investigating unsolvable contingencies
4. Consider all elements of situational awareness in the NERC Operating Standards
5. Identify issues where best practices are nonexistent or insufficient
6. Recognize that there may be more than one "best practice" for a particular aspect of tool utilization and support
7. Consider other tools currently in use to supplement or back up state estimators or real-time contingency analysis applications
8. Address human factors engineering ("man-machine interface")
9. Investigate minimum staffing requirements to support real-time tools
10. Address real-time data acquisition, quality, and time-stamping for data used to drive real-time tools
11. Address management understanding of and commitment (funding and people) to provide appropriate tools and support
12. Identify and consider similar work that may have already been done within the Regions or sub-regions
13. Identify and consider similar work that may have already been published by EPRI [Electric Power Research Institute], IEEE [Institute of Electrical and Electronics Engineers], or other organizations
14. Take into account regional differences in preparing the interim guidelines and final recommendations.

Understanding RTBPTF's Scope

RTBPTF's understanding of its scope depends on three key concepts: the meaning of the term "best practices," the meaning of the term "situational awareness," and the relationships among real-time reliability tools and practices. The task force's considered interpretation of these three key concepts is fundamental to its approach to its work and to the structure of this report.

Best Practices

The first assignment in RTBPTF's scope is to define the term "best practice" as it applies to the task force's charge. However, the concept of best practices extends beyond RTBPTF's scope; OC created the Best Practices Task Force to define this term and identify where or how best practices apply.

The OC Best Practices Task Force final report[9] states:

> The reports following the August 14, 2003 blackout specifically referred to 'best practices,' and the U.S.-Canada Power Outage Task Force final report of April 5, 2004 suggested that the industry establish best practices in certain areas. But these reports and recommendations did not define what best practices were – they assumed the reader would infer the meaning from the context of the report or recommendation.

The Best Practices Task Force report lists specific recommendations from the blackout reports that refer to best practices and summarizes its mission by stating:

> NERC is addressing these recommendations in various reports, documents, and on-going committee tasks. But after considerable research, the task force found there was no single definition of best practices. We also hear the term best practices in reports and committee discussions now and then to describe procedures that, while not standards, are generally accepted as "good things to do," and that work well. However, NERC has never attempted to either define best practices or suggest where or how they could be used. Are best practices in some unique way better than guidelines or examples of excellence? Or do people refer to best practices in the more general sense of "these are good things to do," or "these are ways to achieve excellence?"

The OC's Best Practices Task Force conclusions can be paraphrased as follows[10]:

- NERC has adopted a comprehensive set of mandatory reliability standards, and the Best Practices Task Force believes that adding a comprehensive collection of voluntary practices that represent the years of wisdom and achievements in interconnected systems operation would be a worthwhile goal.

[9] *Best Practices Task Force Report: Discussions, Conclusions, and Recommendations*. 2005. December 1.

[10] These conclusions are paraphrased from the *Best Practices Task Force Report: Discussions, Conclusions, and Recommendations.* 2005. December 1.

These practices (aptly termed as “good things to do”) would complement existing NERC mandatory reliability standards.

- The Best Practices Task Force believes that there are several existing sources within NERC that can be drawn upon to serve the purpose stated above. These include Examples of Excellence, former NERC Operating Guides, Regional Guides, and surveys of operating practices (e. g., RTBPTF Survey).
- The Best Practices Task Force sees no need to develop a separate set of documents called best practices because that term does not have a uniform definition in our industry; it means different things to different people. Operating Guidelines, as well as NERC’s Examples of Excellence, will provide two different kinds of resources for promoting operations excellence. Both are developed by industry experts for industry experts, relate well to the standards, can provide meaningful recommendations for promoting excellence in systems operation, and are voluntary. The key difference between examples of excellence and operating guidelines is that the former are unique to individual organizations and may not apply to the wide interests of the industry, while the latter are more applicable across the industry. Both are valuable, but are not substitutes for one another.

RTBPTF adopted the Best Practices Task Force recommendations and organized RTBPTF deliverables accordingly. Thus, the reader will see in this report, where applicable, recommendations for operating guidelines and descriptions of examples of excellence. (Examples of excellence are listed briefly in the applicable sections of the report and described in more detail in Appendix E).

Situational Awareness

Because lack of situational awareness was determined to be central to causes of the 2003 blackout and because this term clearly expresses the purpose of using real-time reliability tools, RTBPTF explicitly added “situational awareness” to its scope.

RTBPTF defines “situational awareness” as ensuring that accurate information on current system conditions is continuously available to operators. This includes information on the current state of bulk electric system elements as well as on the potential impact of contingencies that might affect these elements. This information must be accurate, dependable, timely, and comprehensive enough for operators to rapidly and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations.

Relationships Among Real-Time Tools and Practices

The real-time reliability tools that are the core subject of this report[11] are fundamental to operators' situational awareness and ability to take prompt, effective corrective action. However, the quality of information supplied by these tools depends on the quality of telemetry and other real-time data as well as on situational awareness practices, system modeling practices, and tool maintenance and availability. The task force's understanding that all these elements are necessary for operator situational awareness was central to its decision to address the following tools and practices:

Real-Time Data Collection — Collecting raw real-time data is the first step in the complex process of producing the accurate, dependable, readily understood information that operators need to maintain situational awareness. Real-time models must be updated with the current status of all modeled elements and the current values of power flows and voltages so that tools such as the network topology processor and state estimator can convert these data into the accurate and dependable information operators need to maintain situational awareness. Thus, RTBPTF included real-time data collection in its scope.

Situational Awareness Practices – Information from real-time reliability tools is only meaningful if operators know how to act on it – that is, how to modify operational strategy in response to real or potential degradation in the reliability of the portion of the bulk electric system for which they are responsible. In some situations, documented procedures ("situational awareness practices") must be established to ensure that operators know the possible or required actions to take. Because it is essential that the information provided by real-time reliability tools allows operators to act to maintain system reliability, RTBPTF included situational awareness practices in its scope.

Modeling Practices — Real-time tools, such as the state estimator and contingency analysis, require a real-time mathematical model of some portion of the bulk electric system in order to function. The size, scope, and content of the required model are functions of the size, location, and scope of responsibility of the entity using the real-time tools. Even the best-designed, advanced tools can be severely compromised by inaccuracies and omissions in the network models upon which they rely. The value of the information provided to operators by real-

[11] RTBPTF focuses only on real-time tools to aid system operators' situational awareness, as called for by the NERC and Outage Task Force reports on the investigation of the 2003 blackout. Thus, RTBPTF's investigation did not include long-term, medium-term, day-ahead, or training tools although the task force recognizes that these tools may be essential for carrying out entities' other reliability-related responsibilities. Similarly, RTBPTF did not consider real-time tools related to market or economic operations.

time reliability tools thus depends heavily on the practices used to build and maintain the requisite models. Therefore, RTBPTF included modeling practices in its scope.

Support and Maintenance Tools – Operators need to be aware of the status of their real-time tools. If a computer problem, data-link failure, or other circumstance interferes with the function of a real-time tool, the operators who rely upon that tool need to be informed so that they will not unknowingly rely on outdated or incorrect information and can take appropriate backup steps. Therefore, RTBPTF included operator awareness of the availability of real-time tools in its scope.

Figure 1 illustrates the interrelationships of the five major topics addressed in this report. Each category represented in Figure 1 is a major section heading in both the Real-Time Tools Survey and this report, as explained in more detail in the sections on the survey, task force recommendations, and report organization below. The RTBPTF adopted an inclusive perspective by explicitly addressing supporting applications, practices, and processes related to real-time tools.

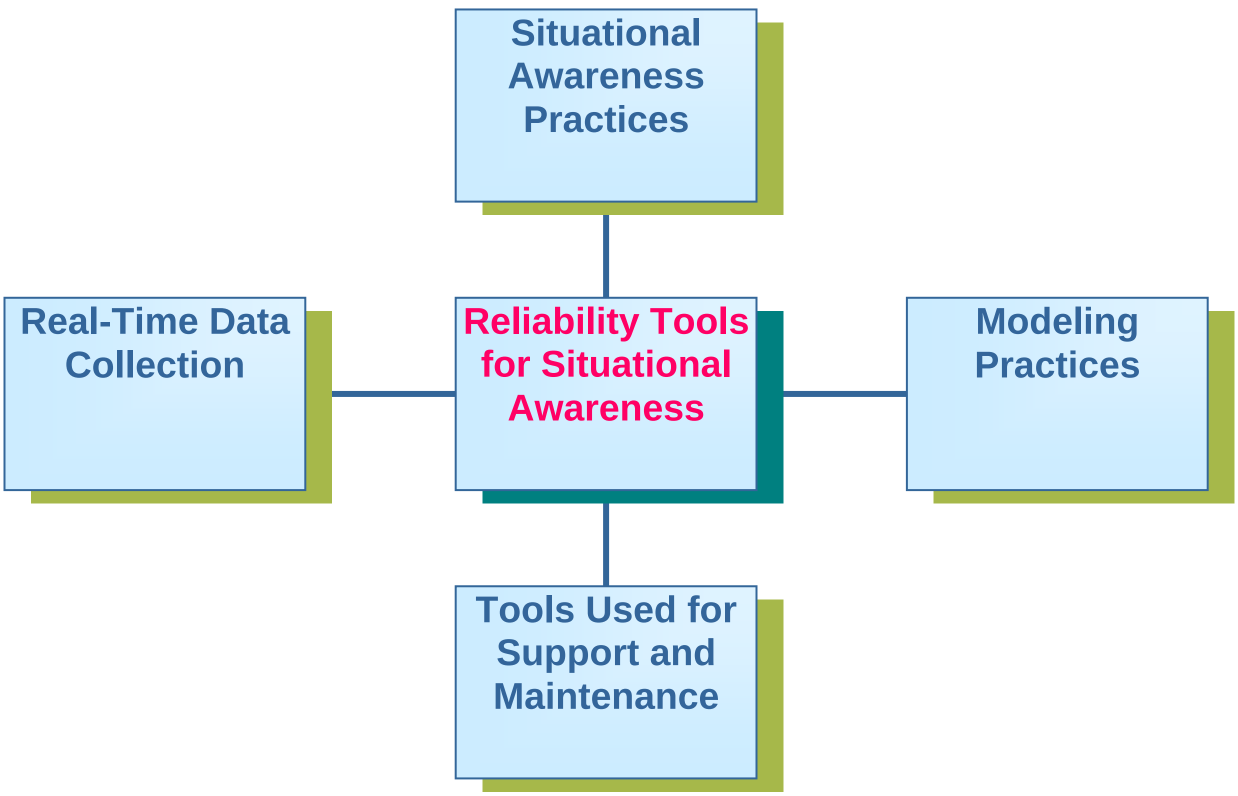

Figure 1. Real-Time Tools and Supporting Practices and Processes.

Survey Approach and Analysis

RTBPTF's principal activity was the development, administration, and analysis of the Real-Time Tools Survey. From fall 2004 through spring 2005, RTBPTF developed the survey, which gathered detailed information on the topics below. For more information on the survey's development, please see Appendix A.

Real-Time Data Collection

This section of the survey addresses the following real-time data, which are needed as input for real-time reliability applications:

- Telemetry data
- Inter-control center communications protocol (ICCP)-specific data
- Miscellaneous data

The questions in this section of the survey focus on the types of telemetry and other near-real-time data that respondents use in Supervisory Control and Data Acquisition/Energy Management System (SCADA/EMS) and network and other applications to monitor the bulk electric system. The data addressed in this section could come from SCADA, ICCP (or other forms of inter-utility data links), Inter-regional security network (ISN), or other systems communicating in continuous real- or near-real-time operation.

Modeling Practices

This section of the survey addresses two topics related to real-time network models:

- Model characteristics
- Modeling practices and tools

The questions in this section of the survey focus on several issues, including, but not limited to: model size, model fidelity, real and reactive load modeling, sensitivity analysis, accuracy analysis, validation, measurement observability, and update and data exchange procedures.

Reliability Tools for Situational Awareness

This section of the survey covers tools used to ensure reliable operations and maintain situational awareness, including:

- Alarm tools
- Visualization tools
- Network topology processor
- Topology & analog error detection
- State estimator
- Contingency analysis
- Critical facility loading assessment (CFLA)

- Power flow
- Study real-time maintenance (SRTM)
- Voltage stability assessment
- Dynamic stability assessment
- Capacity assessment application
- Emergency tools
- Other current, operational tools
- Other future tools

Situational Awareness Practices

This section of the survey addresses operating practices, processes, and procedures that support or maintain situational awareness in the following areas:

- Reserve monitoring
- Alarm response
- Conservative operations
- Operating guides (mitigation plans)
- Load-shed capability awareness
- System reassessment and reposturing
- Blackstart capability awareness

The questions in this section of the survey focus on eliciting information about practices to ensure that operators a) have the information they need to be aware of potentially unreliable system conditions and b) know what actions they can take to maintain reliability.

Support and Maintenance Tools

This section of the survey addresses support tools and practices that are essential to ensuring the integrity and availability of real-time reliability tools, including:

- Display maintenance tool
- Change management tools & practices
- Facilities monitoring
- Critical applications monitoring
- Trouble reporting tool

Survey Participation

The survey was administered in summer and fall of 2005 through a secure, web-based server hosted by NERC in Princeton NJ.[12] RTBPTF invited survey

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[12] Lawrence Berkeley National Laboratory developed the software implementation and web interface for the survey and created a database and software tools to aid RTBPTF in analyzing survey results. NERC and RTBPTF members gratefully acknowledge the support of Lawrence Berkeley National Laboratory of the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability for these activities.

responses from all registered reliability coordinators (RCs), transmission operators (TOPs), balancing authorities (BAs), and any other entity using real-time tools.

The response to the survey was excellent, especially in view of its length and the considerable effort required completing it. As shown in Figure 2, all 17 North American RCs participated in the survey. Figure 3 shows the additional 42 TOPs and/or BAs (that are not also RCs) that participated. This level of participation means that the survey responses provide a comprehensive snapshot of the current practices of a significant and geographically diverse portion of the North American electric industry. For more information on survey participation, please see Appendix B.

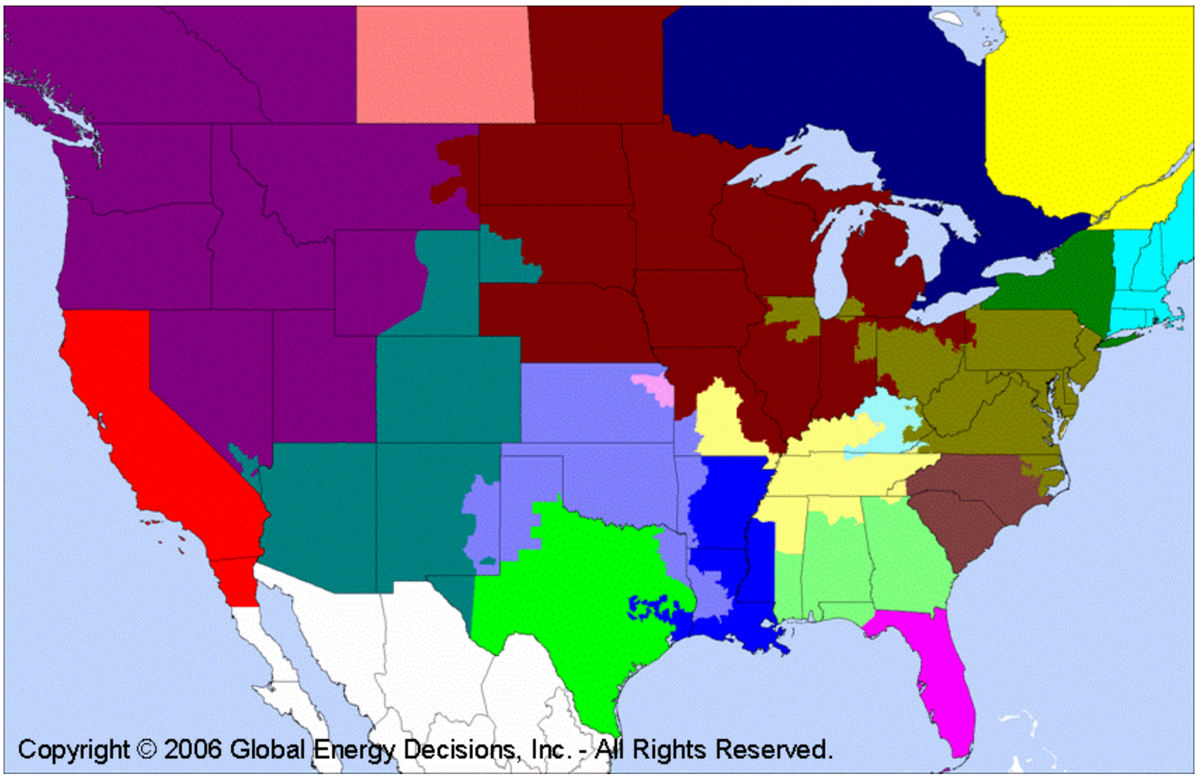

Figure 1 – Footprint of RCs that participated in the Real-Time Tools Survey

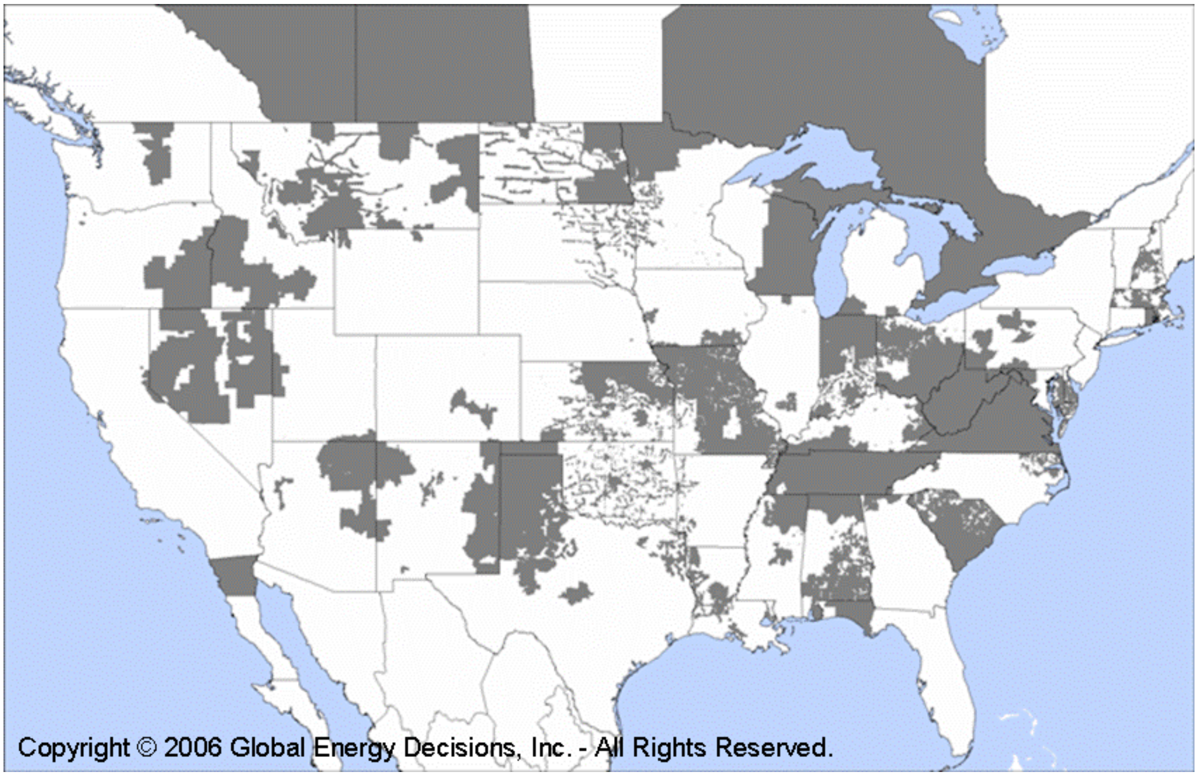

Figure 2 – Footprint of TOPs and BAs (that are not also RCs) that participated in the Real-Time Tools Survey

Survey Analysis

RTBPTF analyzed the survey responses in 2006. First, the task force distilled initial findings by topic and reviewed these findings in relation to the *Outage Task Force Final Blackout Report*, *NERC Blackout Report*, and other relevant background material. The task force focused on issues directly related to reliability, i.e., findings related to tools and situational awareness issues that had been identified as causes of the blackout. RTBPTF identified patterns of similar responses that indicated prevailing industry practices and then reviewed existing reliability standards to see how these tools and issues were addressed. Finally, the task force identified major issues that needed to be resolved. For more information on the survey analysis methodology, please see Appendix C.

The task force's findings are summarized in the next section below.

Overview of Findings

Based on its analysis of the Real-Time Tools Survey results, the task force made a large number of findings. The key findings for each major section of the report are summarized below with reference to the task force's relevant major recommendations, which are presented in more detail in the Recommendations section later in this introduction.

Real-Time Data Collection

RTBPTF finds that adequate, timely, accurate telemetry data on the current status of bulk electric system elements are essential for situational awareness. Bulk electric system elements that have the potential to impact system operations by causing a system operating limit (SOL) or interconnected reliability operating limit (IROL) violation and that are within an entity's footprint or adjacent to it should be telemetered. Accordingly, telemetry data systems are among RTBPTF's five recommended mandatory real-time tools, as described in the Recommendations section below. RTBPTF also recommends that NERC and the industry clarify the definition of bulk electric system elements and the wide-area-view boundary for telemetry data, consistent with this impact-based definition.

RTBPTF's analysis of the survey findings related to real-time data collection and all of the task force's recommendations on this topic are found in the following sections of this report: Section 1.0, Real-Time Data Collection; Section 1.1, Telemetry Data; Section 1.2, ICCP-Specific Data; and Section 1.3, Miscellaneous Data.

Reliability Tools for Situational Awareness

RTBPTF concludes that situational awareness requires, at a minimum:

- Functioning alarms that notify operators of current or potential violations of limits

- Timely and accurate network topology processing and state estimation to ensure that alarms can be reliably processed (when appropriate) and that meaningful contingency analysis can be performed

- Timely and accurate contingency analysis to identify potential SOL or IROL violations

Accordingly, alarm, network topology processing, state estimation, and contingency analysis tools are included in RTBPTF's five recommended mandatory real-time tools. Additional real-time tools and processes for power flow, load-shed capability, and visualization techniques are included as part of other RTBPTF recommendations.

RTBPTF's analysis of the survey findings related to real-time tools for situational awareness and all of the task force's recommendations on this topic are found in the following sections of this report: Section 2.0, Reliability Tools for Situational Awareness; Section 2.1, Alarm Tools; Section 2.2, Visualization Techniques; Section 2.3, Network Topology Processor; Section 2.4, Topology and Analog Error Detection; Section 2.5, State Estimator; Section 2.6, Contingency Analysis;

Section 2.7, Critical Facility Loading Assessment; Section 2.8, Power Flow; Section 2.9, Study Real-Time Maintenance; Section 2.10, Voltage Stability Assessment; Section 2.11, Dynamic Stability Assessment; Section 2.12, Capacity Assessment; Section 2.13, Emergency Tools; Section 2.14, Other Tools (Current and Operational). [An additional section, Section 2.15 Other Tools (Future), was planned but is omitted from this report because the survey responses yielded insufficient information on this topic.]

Situational Awareness Practices

The task force concludes that documented conservative operations practices are a key element of situational awareness practices and thus includes conservative operations plans in its recommendations. The task force also recommends, in its list of major issues that should be addressed to enhance the effectiveness of real-time tools, that NERC and the industry specify what constitutes acceptable reactive reserves and load-shed capability.

RTBPTF's analysis of the survey findings related to situational awareness practices and all of the task force's recommendations on this topic are found in the following sections of this report: Section 3.0, Situational Awareness Practices; Section 3.1, Reserve Monitoring; Section 3.2, Alarm Response Procedures; Section 3.3, Conservative Operations; Section 3.4, Operating Guides; Section 3.5, Load-Shed Capability; Section 3.6, System Reassessment and Re-posturing; Section 3.7, Black-Start Capability.

Power System Modeling

Although defining the elements represented in internal network models is relatively straightforward, the task force finds that defining the elements to be represented in external models is much more complex. External models must be appropriately sized and adequately updated and maintained to ensure that they can accurately represent pre- and post-contingency conditions. RTBPTF recommends that NERC and the industry develop criteria, guidelines, and standards for internal and, especially, external system models as well as data exchange. As with telemetry data, RTBPTF recommends defining what constitute bulk electric system elements and the wide-area view based on the potential impacts of these elements on an entity's ability to operate reliably; these definitions should form the basis for model development and data exchange standards.

RTBPTF's analysis of the survey findings related to power system modeling and all of the task force's recommendations on this topic are found in the following sections of this report: Section 4.0, Power System Models; Section 4.1, Model Characteristics; Section 4.2, Modeling Practices and Tools.

Support and Maintenance Tools

RTBPTF finds that RC and TOP control centers use a variety of applications and practices to monitor the status of real-time tools and supporting computer systems and communications networks. Thus, RTBPTF's recommendations include requirements for critical applications and facilities monitoring tools.

RTBPTF's analysis of the survey findings related to support and maintenance tools and all of the task force's recommendations on this topic are found in the following sections of this report: Section 5.0, Support and Maintenance Tools; Section 5.1, Display Maintenance Tool; Section 5.2, Change Management Tools and Practices; Section 5.3, Facilities Monitoring; Section 5.4, Critical Applications Monitoring; Section 5.5, Trouble Reporting Tool.

Criteria for Developing Recommendations

RTBPTF formulated its recommendations for real-time tools based on its survey analysis and on the following five key criteria, which the task force developed based on its assigned scope and the results of the 2003 blackout investigation:

1. Support NERC Reliability and Market Interface Principles.[13]

2. Address current needs and known gaps, such as those identified in the August 14, 2003 blackout reports by NERC and the Outage Task Force and in the *FERC Staff Assessment*. (RTBPTF also considered recommendations made by FERC Consultant Frank Macedo in his presentation, "Reliability Software: Minimum Recommendations and Best Practices," at the July 14, 2004 FERC technical conference.)[14]

3. Represent effective and feasible practices that are prevalent in the industry today. That is, the recommendations must be supported by the survey findings.

4. Identify performance requirements for which compliance can be assessed unambiguously and, to the extent defensible based on survey findings, through the use of quantitative metrics.

5. Represent the consensus of active RTBPTF members.

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[13] ftp://ftp.nerc.com/pub/sys/all_updl/tsc/stf/ReliabilityandMarketInterfacePrinciples.pdf

[14] Macedo, Frank, Consultant to FERC. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

Recommendations

RTBPTF's major recommendations are summarized below. A summary list of all the recommendations in this report is presented in Table ES-1. The details of each recommendation appear in the relevant subsection of the report.

RTBPTF makes major recommendations in three key areas. The first two recommendations summarized below apply to RCs, TOPs, and other entities with similar responsibility:

1. Reliability Toolbox – Require five real-time tools as well as performance and availability metrics and maintenance practices for each. The required tools are:

- Telemetry data systems
- Alarm tools
- Network topology processor
- State estimator
- Contingency analysis

2. Enhanced Operator Situational Awareness – Require standards and guidelines for situational awareness practices, including:

- Power-flow simulations
- Conservative operations plans
- Load-shed capability awareness
- Critical applications and facilities monitoring
- Visualization techniques

The task force also recommends that NERC:

3. Address Six Major Issues to enhance the effectiveness of real-time tools:

1) Definition of the bulk electric system
2) Definition of the wide-area-view boundary
3) Development of system models and standards for exchange of model information
4) Specification of acceptable reactive reserves
5) Determination of adequate load-shed capability
6) Provision of adequate funding and staffing for maintaining and upgrading real-time tools

Each of these recommendations is described in more detail below.

Require the Use of Five Real-Time Tools

RTBPTF recommends that, to ensure reliability monitoring of the bulk electric system and maintenance of situational awareness, five real-time tools become mandatory with quantitative measures for minimum acceptable levels of performance for both RCs and TOPs (as a revision to TOP-006).[15] These required tools should be viewed as the core elements of an operator's "reliability toolbox." Figure 4 illustrates the relationships among these tools (and supporting applications).

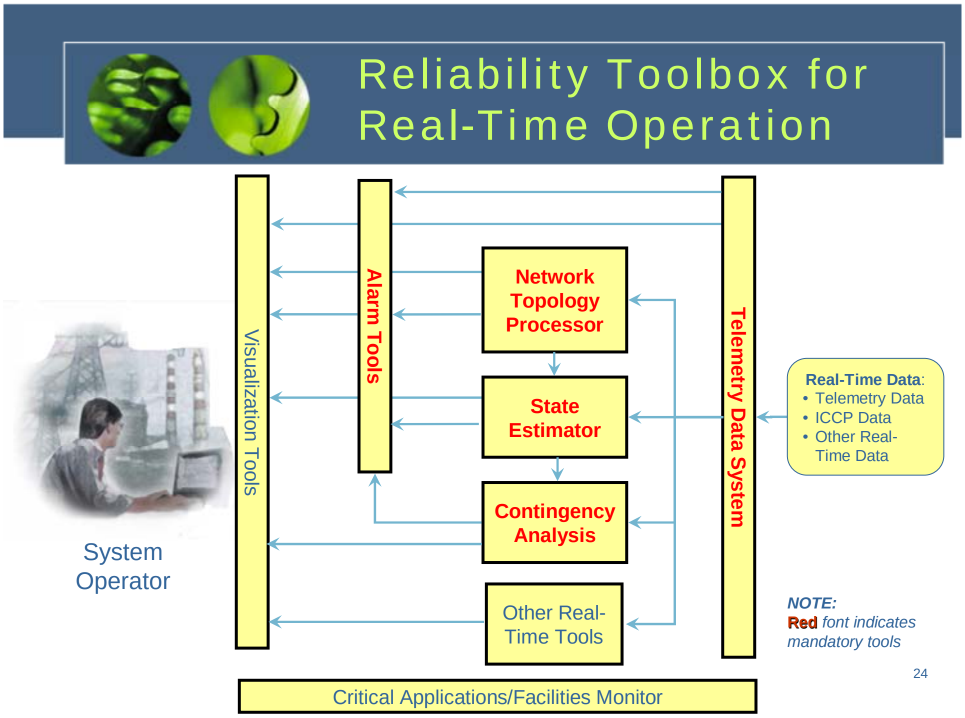

Figure 4 – Reliability Toolbox

RTBPTF recommends that the use of these five real-time tools be mandatory for all RCs and TOPs. RTBPTF further recommends that these requirements apply to any entity that has been delegated responsibility, by an RC or TOP, to operate these tools, regardless of the entity's registered designation. "Delegated responsibility to operate these tools" means the entity uses any of these tools to support or complement the RC's or TOP's ability to operate the bulk electric system reliably in accordance with formal agreements, contracts, or previously established practices or procedures.

[15] RTBPTF recognizes that differences will arise naturally between TOPs and RCs in the use of these tools. For example, the definition of the wide-area boundary (for RCs) and the "local" transmission system (for TOPs) will have implications for the scope of the network model that each relies upon.

Mandatory Tool #1: Telemetry Data Systems – Telemetry data systems update status and analog values from SCADA/EMS (via ICCP, ISN, etc.) continuously in real time or near-real time. These systems are the primary direct and indirect sources of situational awareness for operators (they function as indirect sources when they support other applications).

RTBPTF recommends modifying existing standards to require telemetry data system use. The task force also makes four supporting recommendations for telemetry data systems:

1) Increase the minimum update frequency for operational reliability data from once every 10 minutes to once every 10 seconds.[16]

2) Standardize the procedures, processes, and rules governing key data exchange issues.[17]

3) Institute a requirement for data availability from ICCP or other equivalent systems, based on the ratio of "good" data received (as defined by data quality codes) to total data received. The ratio must exceed 99 percent for 99 percent of the sampled periods during a calendar month. In addition, the ratio must not be less than 99 percent for any 30 consecutive minutes.

4) Establish minimum response times for restoration of data exchange between control centers following the loss of a data link or other problems within the source system. As part of this requirement, a trouble-resolution process standard must be developed that requires all entities responsible for management and maintenance of ICCP or equivalent systems to identify, with data recipients that could be affected by a loss of data exchange capability, a mutually agreeable restoration target time. The standard process must also include service-restoration escalation procedures and prioritization criteria.

RTBPTF recognizes that the many parties involved in monitoring, transmitting, and receiving data share the responsibility for maintaining the availability of high-quality data. Assignment of specific responsibilities for sub-par performance is not within RTBPTF's scope but should be considered as part of the standards development process.

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[16] Section 1.1, Telemetry Data, contains a complete list of data elements to which the recommended update frequency should be applied.

[17] These issues include: interoperability of ICCP and equivalent systems, data access restrictions, data-naming conventions, change management and coordination, joint testing and data checkout, quality codes, and dispute resolution.

Mandatory Tool #2: Alarm Tools – Alarm tools give real-time visual and audible signals to alert operators and others about events affecting the state of the bulk electric system. Alarms may be initiated by information transmitted directly from telemetry data systems or other applications, such as the state estimator and contingency analysis. Alarms are essential for ensuring operator situational awareness.

RTBPTF recommends modifying existing standards to require use of alarm tools. RTBPTF also recommends mandatory processes to help ensure that alarm tools are always available. RTBPTF supports filtering, prioritizing, and grouping alarms as an important feature common to most alarm tools. However, the task force does not recommend making additional intelligent alarm-processing capabilities mandatory at this time because survey results show that adoption of these capabilities is not yet widespread in the industry.

Mandatory Tool #3: Network Topology Processor – A network topology processor can be used in more than one way: to support visualization tools in identifying electrical islands or isolated or open-ended equipment, and to convert a nodal network model, based on SCADA breaker and switch statuses, into a bus-branch model for use by other network applications. Use of this tool for the latter purpose is essential because two applications that are mandatory for situational awareness, the state estimator and contingency analysis, cannot be run without this conversion.

RTBPTF recommends modifying existing standards to require use of a network topology processor.[18] RTBPTF also recommends specific availability requirements, which depend on the functions supported by the tool.

Mandatory Tool #4: State Estimator – A state estimator performs statistical analysis using imperfect, redundant telemetered data from the power system and a power system model to assess the system's current condition. State estimator output is the primary input for all network analysis applications, such as contingency analysis and power flow, and can also be used to generate alarms for overloads or voltage problems on branches and buses. If the state estimator is not working or is working incorrectly, real-time network analysis, such as contingency analysis, either cannot be performed or will not produce valid results. Situational awareness depends on valid contingency analysis results.

RTBPTF recommends modifying existing standards to require use of a state estimator. RTBPTF also recommends specifying minimum requirements for the availability of valid, useful state estimator results based on two metrics:

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[18] This and the following RTBPTF recommendations for two additional mandatory real-time tools should be viewed jointly. For example, RTBPTF recognizes that a network topology processor is sometimes maintained as an integrated process within a state estimator.

1) The state estimator must have at least one converged solution (i.e., a state-estimated solution) for at least 97.5 percent of clock 10-minute periods (six non-overlapping periods per hour) during a calendar month, and

2) The state estimator must have at least one converged solution (i.e., a state-estimated solution) for every continuous 30-minute interval during a calendar day.[19]

The quality of state estimator solutions needs to be formally addressed, but RTBPTF concludes that more analysis is required to formulate and specify technically defensible solution-quality metrics and performance requirements. RTBPTF maintains that specification of a single performance metric and target would be inappropriate at this time. Other, corollary issues must be considered, such as whether external model specification is adequate and whether the telemetry data upon which the state estimator depends are valid. Until these issues are addressed, focus on a specific performance metric and target will lead to a false sense of security regarding the quality of state estimator solutions. Thus, at this time, RTBPTF recommends the development of operating guidelines for solution-quality metrics and a parallel process of tracking and analyzing state estimator performance.[20]

Mandatory Tool #5: Contingency Analysis – A contingency analysis tool simulates power flow for a set of contingencies and calculates the post-contingency thermal loading on and/or voltages at a set of monitored facilities. The results from contingency analysis identify potential SOL and IROL violations. These results, in turn, inform alarm tools (including visualization tools) and may initiate other applications.

RTBPTF recommends modifying existing standards to require contingency analysis. RTBPTF also recommends specifying minimum acceptable availability and use of contingency analysis, the definition of contingencies with respect to relay actions, and procedures for addressing failed contingency analysis:

1) Contingency analysis must be run in conjunction with a converged state estimator solution for at least 97.5 percent of clock one-minute periods (six non-overlapping periods per hour) during a calendar month.

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[19] These timing requirements are consistent with NERC's mandate to MISO to fully implement and test its state estimator and contingency analysis tools "to ensure that they can operate reliably no less than every 10 minutes" (see the *NERC Blackout Report*). These requirements are also consistent with the requirement that operators must be aware of IROL and SOL violations and be able to take action to address them within no more than 30 minutes.

[20] Examples of solution-quality metrics that should be considered include: trend of cost index (sometimes called a "performance index"), trend of number of anomalous measurements, ranked normalized residuals of individual measurements, maximum MW and Mvar mismatch, trend of number of iterations, and major topology changes.

2) Contingency analysis must be run at least once for every continuous 30-minute interval during a calendar day.[21]

3) Real-time contingencies must be defined so that they accurately reproduce the results of the actions of protective relays, which remove elements from service to minimize damage or stop the spread of undesirable system conditions.[22]

4) The total number of “unsolved” contingencies (i.e., contingencies for which the power flow fails to converge and therefore does not produce a solution) must be recorded, at a minimum, every 30 minutes. The actions taken to resolve unsolved contingencies and procedures to investigate and resolve unsolved contingencies must be documented.

Because the Reliability Toolbox is an overarching recommendation that draws on findings from many sections of this report, the rationale for this recommendation and the recommended wording for the revisions to standard TOP-006 appear, in the same format as used for the other recommendations throughout this report, in a separate section, Reliability Toolbox Recommendation and Rationale, following this introduction.

Require Supporting Tools and Practices

RTBPTF makes several major recommendations regarding tools and practices that support the five mandatory real-time tools in the Reliability Toolbox:

Power Flow – The power-flow application calculates the state of the power system (flows, voltages, and angles) using available input data for load, generation, net interchange, and facility status. On-line power flow is widely used to assess system conditions or perform look-ahead analysis. It is also used in “n-1” contingency analysis and to identify potential future voltage collapse or reliability problems.

[21] The justifications for these two performance metrics and minimum acceptable performance targets are the same as those described previously for the state estimator.
[22] This recommendation is intended to clarify the current reliability standard to ensure that the list of contingencies includes all bulk electric system elements that, when out of service, can cause an SOL or IROL violation or overload on any other facility. In other words, although NERC standard FAC-010 considers only individual bulk electric system elements, RTBPTF recommends that the definition of a single contingency, for the purpose of this recommendation, include explicit consideration of network topology. This is to ensure that single events that result in the simultaneous outage of multiple bulk electric system elements are analyzed.

RTBPTF recommends revising existing standards to require RCs and TOPs to perform one-hour-ahead power-flow simulations following critical system events, extreme load conditions, large power transactions, and major planned outages.

Conservative Operations – Conservative operations refer to intentional, proactive practices in response to unknown, insecure, or potentially risky system conditions. Conservative operations are intended to move the system to a known, secure, and low-risk operating posture. For example, the power system is postured differently for different impending conditions, such as hurricanes, ice storms, cold fronts, etc.

RTBPTF recommends revisions to and coordination among several existing reliability standards to require that each RC and TOP have documented conservative operations plans and procedures. These plans and procedures must identify credible conditions that could lead to an unknown, insecure, or potentially risky operating state and the appropriate actions that operators are expected to take in response.

Awareness of Load-Shed Capability – Load-shed capability awareness is current knowledge of the status, availability, magnitude, and time-to-deploy of all customer load that can be dropped on an emergency basis. Without this knowledge, RCs and TOPs cannot ensure that they can successfully perform this control action of last resort; this knowledge is an essential element of situational awareness.

RTBPTF recommends modifying existing standards to require operator awareness of actual load-shed capability in real time. However, RTBPTF recognizes that procedures for determining the amount, location, and maximum time-to-deploy of load-shed resources must be clarified. This topic is addressed separately below as one of the six major issues RTBPTF recommends that NERC and the industry address to enhance the effectiveness of real-time tools.

Critical Applications and Facilities Monitoring – Critical applications and facilities monitoring tracks the status and availability of real-time tools, including, but not limited to, the five recommended mandatory tools described above. As noted earlier, RTBPTF recommends measurable indices of performance (metrics) and minimum performance requirements based on these indices for each of the five mandatory tools, to ensure that the data produced by those tools are meaningful. However, critical applications and facilities monitoring is also needed to ensure that the information provided by these tools is current and continuously available to operators and technical support staff.

RTBPTF recommends requirements for a separate process (or support tool) that continuously monitors the availability and status of the five mandatory reliability tools as well as other critical tools.[23] RTBPTF also recommends mandatory reporting requirements for event logs and maintenance documentation.

Visualization Techniques **–** Visualization techniques are a group of user-interface applications, tools, and displays that provide concise visual monitoring and enhanced multiple views of relevant power system data in real time to operators and others.

RTBPTF recommends modifying existing IRO and TOP reliability standards to require the use of visualization tools as part of the measures for compliance with existing NERC reliability standards. RTBPTF also endorses ongoing efforts to research and develop visualization techniques consistent with Recommendation 13 of the *Outage Task Force Final Blackout Report.*

RTBPTF also recommends that NERC:

1) Establish a Visualization Tools Working Group (VTWG) to foster and facilitate sharing of industry best practices for use of visualization tools. This working group could continue to recommend and develop standards and operating guidelines for best methods and practices for presenting information to operators.

2) Establish industry and technical forums, involving academic, research, and other organizations, that focus on visualization tools.

Address Six Issues to Enhance the Effectiveness of Real-Time Tools

RTBPTF's above recommendations stand on their own, and NERC and the industry should implement these recommendations as soon as practicable. In addition, RTBPTF has identified six issues that are closely related to its recommendations and that NERC and the industry should address to enhance the effectiveness of real-time tools.

Issue #1: Bulk Electric System Elements Should be Defined. The effectiveness of *s*everal of RTBPTF's recommendations depends on the adequacy of telemetry, modeling, and exchange of appropriate data regarding bulk electric system elements. RTBPTF recommends that NERC and regional reliability organizations (RROs) define criteria for what constitute bulk electric system elements and that

[23] RTBPTF notes that NERC cyber-security standards address the availability of critical tools. However, cyber-security standards do not address operator situational awareness. Cyber-security standards focus primarily on protecting and securing critical cyber assets (e.g., CIP-007) and do not adequately acknowledge or address operators' needs for these tools to monitor the bulk electric system and maintain situational awareness.

RCs create and maintain a comprehensive, consistent list of all bulk electric system elements within their respective footprints.

In support of actions by others to define bulk electric system elements and based on RTBPTF's system-operations perspective, the task force recommends basing the definition of bulk electric system elements on a clear, unambiguous NERC and regionally approved impact-based methodology. Application of this method should lead to a definition of bulk electric system elements that refers only to electrical facilities that, if out of service, could lead to an SOL or IROL violation. RTBPTF does not support a definition of bulk electric system elements that is based on electrical characteristics. RTBPTF formulated all of its recommendations from this perspective.[24] The task force notes this perspective both to inform ongoing industry discussions and to provide a context for its own recommendations.

Issue #2: The Wide-Area Boundary Should be Defined. Standard IRO-003's Purpose Statement says that "[t]he Reliability Coordinator must have a wide area view of its own Reliability Coordinator Area and that of neighboring Reliability Coordinators." The NERC glossary defines "wide area" as "[t]he entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits."

RTBPTF defines "wide-area view" as the monitoring boundary for RCs. Several of RTBPTF's recommendations depend on appropriate definition of and exchange of information about bulk electric system elements. For RCs, the identification of their "wide area" of responsibility depends on the definition of bulk electric system elements.

In this report, RTBPTF introduces the concept of a "wide-area-view boundary," defined as the network model boundary for the "wide area" as defined by NERC. For reliability coordinators, the wide-area-view boundary defines the minimum required network model needed to support the monitoring requirements for the wide area. This network model should contain all the bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) encompassed by the wide-area-view boundary. Sections 4.1, Model Characteristics, and 4.2, Modeling Practices and Tools, of this report discuss the wide-area-view boundary in more detail.

The wide area that a reliability coordinator must monitor must include the bulk electric system elements in adjacent reliability coordinator footprints that individually (if they were out of service) could impact calculations of SOLs or IROLs beyond a yet-to-be-defined threshold. The wide-area-view boundary must

[24] The Real-Time Tools Survey did not explicitly explore this topic. The RTBPTF perspective is based solely on the professional expertise of the task force members.

include the wide area plus the bulk electric elements in adjacent areas that are collectively needed to ensure accurate analyses of SOLs and IROLs in the wide area.[25]

RTBPTF recommends that NERC and the RROs establish criteria for determining the “wide area boundary” and the RC’s “wide-area view.” RTBPTF recommends that the wide-area-view boundary should be determined based on an impact-based methodology – that is, a process to determine the critical flow and status information from adjacent reliability coordinator areas based on detailed system studies to allow the calculation of IROLs. These uniform formal criteria would clarify the extent and detail required for the “wide area.”

Regarding issues #1 and #2 above, RTBPTF recognizes that the criteria for defining “bulk electric system” and “wide area,” when applied to real-time operations and modeling, will directly affect the number of data required and thus will ultimately affect the content and size of the models used by network applications. RTBPTF’s recommended approach is intended to insure that the required elements of the bulk electric system are appropriately defined and that data for real-time operation and modeling are adequate. See the sidebar *RTBPTF Thoughts on Bulk Electric System, Wide-Area View, and Modeling Requirements* for an explanation of RTBPTF’s view of the interrelationship of issues #1 and #2 and their effect on real-time network models (issue #3 below).

Issue #3:   Mandatory Procedures for Specifying Acceptable Reactive Reserves Should be Developed. Reactive reserves monitoring is a documented set of procedures, practices, or guidelines for maintaining awareness of current and near-term reactive reserve capability. Although current NERC standards define acceptable operating (real) reserves, they do not define acceptable reactive reserves. Defining reactive reserves is difficult because they must be evaluated with explicit consideration of network topology and the balance between reactive sources and sinks in local regions within the network. RTBPTF believes that mandatory requirements for real-time tools for reactive reserve monitoring would be highly desirable; however, before such recommendations can be formulated, NERC must define technically justified and feasible-to-implement requirements for determining the appropriate amount and location of acceptable reactive reserves and clarifying how reliability coordinators should monitor these reserves. This issue is explored more fully in Section 3.1, Reserve Monitoring, of this report.

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[25] That is, RTBPTF recommends that the wide-area-view boundary for RCs be referred to as “minimum boundary conditions based upon a defined set of system conditions, contingencies, and required performance criteria.” Operating Limit Definition Task Force (OLDTF). 2007. *Reliability Criteria and Operating Limits Concepts Reference Document - System Limits - Version 4, Draft 2*. January 29.

Issue #4: Mandatory Procedures for Determining Acceptable Load-Shed Capability Should be Developed. RTBPTF agrees with the *FERC Staff Assessment* that NERC standards do not adequately define requirements for load-shed capability. Thus, although situational awareness requires that operators know how much and how fast they can and must deploy load-shed resources (by means of an appropriate real-time tool), NERC must also make technical progress to define requirements for determining the correct amount, location, and maximum time-to-deploy of load-shed resources. This issue is explored more fully in Section 3.5, Load-Shed Capability, of this report.

Issue #5: External Modeling and Data Exchange Practices Should be Improved by Explicit Reference to the Definition of the Wide-Area-View Boundary. A consistent, uniform set of modeling and data exchange practices, procedures, and standards are needed to support creation and maintenance of accurate external models. RTBPTF recommends that these practices, procedures, and standards follow as a natural outgrowth of the definition of bulk electric system elements that are critical to a particular entity and that, therefore, define the wide-area-view boundary for that entity (per the discussion of issues #1 and #2 above). The complete discussion of this issue and the task force's specific recommendations concerning modeling practices are found in Sections 4.0, Power System Models; 4.1, Model Characteristics; and 4.2, Modeling Practices and Tools, of this report.

RTBPTF recommends that NERC create a new task force to focus specifically on recommending minimum standards for real-time models and data exchange, including:

- Grid change notification
- Model data exchange
- ICCP data exchange (see specific recommendations in Section 1.2, ICCP-Specific Data)
- Supplemental support data exchange (e.g., schematics, maps)
- Non-disclosure agreements

The task force recognizes the work already completed by the NERC Data Exchange Working Group (DEWG) in these areas, which is documented in the ISN Node Responsibilities and Procedures document.[26] The task force considers this work a good starting point for definitive and comprehensive requirements.

Issue #6: Adequate Funding and Staffing for Real-Time Tools and Support Should be Ensured. To ensure adequate monitoring and situational awareness, reliability entities' managers must understand the importance of real-time tools and commit to actively supporting required activities and staff. However, RTBPTF

[26] NERC Data Exchange Working Group (DEWG). 2005. *ISN Node Responsibilities and Procedures*. August 4.

was not able to analyze this issue both because significant differences among organizations made direct comparisons difficult and because this analysis requires expertise beyond that of the task force's members. RTBPTF recommends that OC determine an alternate means for addressing this issue.

Next Steps

RTBPTF emphasizes that this report is only the beginning of NERC and industry efforts to improve reliability through better real-time operating tools and practices. There is still much to do to implement the task force's recommendations for revised standards and operating guidelines and to conduct needed additional analyses.

To initiate the next steps in the process, RTBPTF proposes to finish work on the following activities, which will complete the remainder of the task force's scope of work as assigned by OC:

- Append recommendations for revised standards to the existing Standards Review Forms that are included in the NERC Standards Development Plan: 2007–2009.[27]
- Provide technical support to the standards drafting teams.
- Prioritize areas requiring more analysis.
- Write high-level scopes for the analysis required.

Following completion of these activities, RTBPTF will disband.

As described in the report, RTBPTF also recommends the following additional steps, which are outside the scope assigned to the task force by OC:

- ORS should determine how operating guidelines are to be developed and maintained.
- OC should consider asking the RROs to develop these guidelines as "supplements" to the NERC standards.
- NERC should address the areas in need of more analysis.

Organization of this Report

The remainder of this report is organized as follows:

Five major sections describe the findings, analysis, and task force recommendations for the main subject areas of the Real-Time Tools Survey, and a sixth section details the next steps toward implementing RTBPTF's recommendations:

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[27] ftp://www.nerc..com/pub/sys/all_updl/standards/sar/FERC_Filing_Volumes_I-II III_Reliability_Standards_Development_Plan_30Nov06.pdf

Section 1.0, Real-Time Data Collection
Section 2.0, Reliability Tools for Situational Awareness
Section 3.0, Situational Awareness Practices
Section 4.0, Power System Modeling
Section 5.0, Support and Maintenance Tools
Section 6.0, Next Steps

Within each section, a general introduction is followed by sections focusing on the main topic areas in that section. Each topical section is structured as follows:

- **Definition** of the specific topic
- **Background** on the specific topic, including blackout investigation findings related to it
- **Summary of Findings** based on the Real-Time Tools Survey responses
- **Recommendations for New Reliability Standards** (if applicable), including new reliability standards or modifications to existing standards, with rationale for each, and major issues to address to clarify interpretation of existing reliability standards in the context of real-time tools usage, practice, and processes that enhance situational awareness
- **Recommendations for Operating Guidelines** (if applicable), including recommendations and corresponding rationale for new operating guidelines, following the Best Practices Task Force conclusion that best practices are “good things to do” and should complement existing NERC reliability standards; operating guidelines are applicable across the industry, but are voluntary, not mandatory
- **Areas Requiring More Analysis** (if applicable), including recommendations that NERC further study a tool or topic about which the Real-Time Tools Survey results were inconclusive
- **Examples of Excellence** (if applicable), a brief notation that RTBPTF identified examples of excellence for the specific topic, which are detailed in Appendix E

The appendices to this report address Real-Time Tools Survey development (Appendix A), participation (Appendix B), analysis (Appendix C), and web links to aggregate survey results (Appendix D). Appendix E, Examples of Excellence, describes practices related to tools and/or operating procedures that exceed minimum requirements of existing standards, are unique to individual organizations, and may not be applicable throughout the industry.

The report also includes a glossary and an acronym list for the reader’s convenience.

RTBPTF Thoughts on
Bulk Electric System, Wide-Area View, and Modeling Requirements

RTBPTF suggests the following approach to defining bulk electric system elements, the wide-area-view boundary, and modeling requirements:

The list of bulk electric system elements that each reliability coordinator (RC) must maintain shall comprise the bulk electric system elements within the RC's footprint. Call the bulk electric system elements in this list the BES_{RC}.

The wide area that an RC must monitor shall include the BES_{RC} plus the bulk electric system elements in adjacent RC footprints that, individually, if they were out of service, could impact calculations of SOLs or IROLs beyond a yet-to-be-defined threshold. Call the wide area WA and this set of bulk electric system elements in adjacent areas the primary BES_{Adj}.

Thus:

$$WA = BES_{RC} + \text{primary } BES_{Adj}$$

The wide-area view of an RC is simply the information derived from modeling and real-time data made available to the RC operators to fulfill the requirements for monitoring, visualizing, and analyzing the wide area. The wide-area view can extend beyond the wide area.

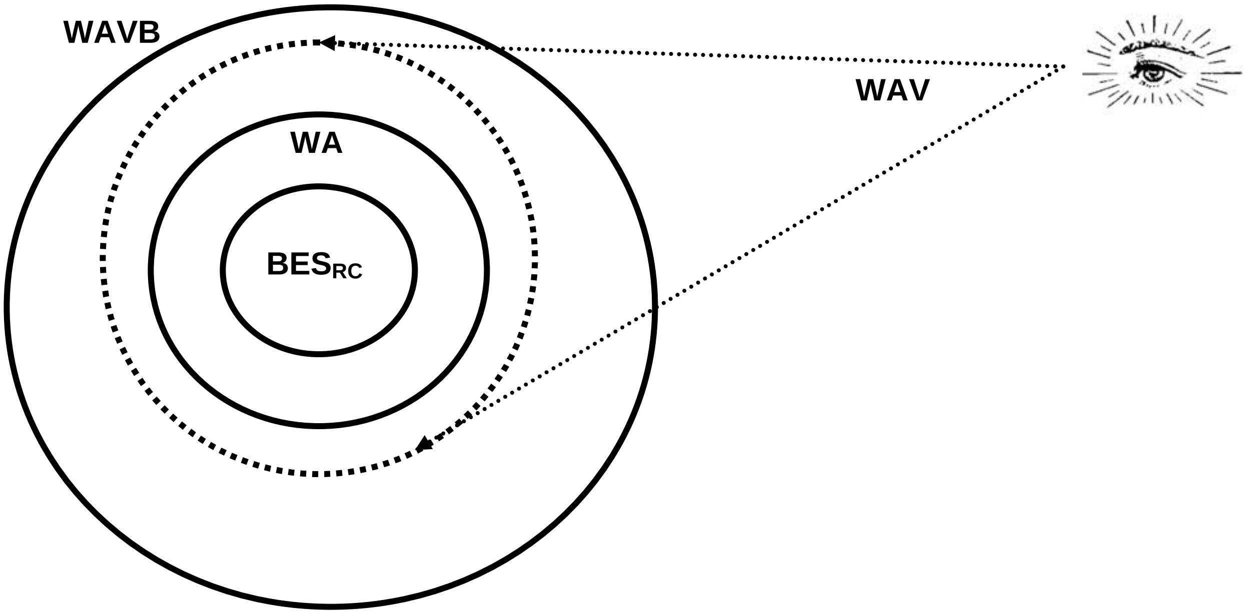
The wide-area-view boundary shall include the wide area plus the bulk electric elements in adjacent areas that are collectively needed to ensure accurate analyses of SOLs and IROLs in the wide area. Call the wide-area-view boundary WAVB and this set of bulk electric system elements the secondary BES_{Adj}.

Thus:

$$WAVB = WA + \text{secondary } BES_{Adj}$$

The internal portion of an RC's real-time network model shall include, at a minimum, the BES_{RC} and any other facilities in the RC footprint needed to ensure accurate analyses of SOLs and IROLs in that RC's footprint.

The external portion of a reliability coordinator's real-time network model shall include, at a minimum, the WAVB.


WAVB
WA
BES$_{RC}$
WAV

Reliability Toolbox Recommendation and Rationale

The RTBPTF recommendation that five real-time tools be required of all reliability coordinators (RCs) and transmission operators (TOPs) addresses tools that are covered in several discrete sections of this report (Section 1.1, Telemetry Data; Section 2.1, Alarm Tools; Section 2.3, Network Topology Processor; Section 2.5, State Estimator; Section 2.6, Contingency Analysis). Therefore, the task force presents the full text of this overarching recommendation separately below, using the same format as for the other recommendations in the specific sections throughout the report.

RTBPTF was charged with defining minimally acceptable capabilities for network analysis and situational awareness tools. By recommending the mandatory tools that make up the Reliability Toolbox as well as specific performance standards and metrics for these tools, RTBPTF believes it has fulfilled this charge to the best of its ability, given the current state of the industry as measured in the Real-Time Tools Survey. All five of the recommended tools enjoy widespread usage in the industry and support the fundamental purpose of maintaining situational awareness and reliable operation of the bulk electric system. The Reliability Toolbox and related performance standards and metrics are technically defensible for today's electric industry, as indicated by the survey results, and will help realize the full potential of these tools. Over time, it may be necessary to reconsider the minimal capabilities of these tools or to consider whether other tools need to be added to the toolbox.

RTBPTF Recommendation

To mandate the Reliability Toolbox, RTBPTF recommends that a new requirement be established under the current Standard TOP-006 (Monitoring System Conditions) to specify the minimum set of monitoring and analysis tools implicitly required by Standard IRO-002 and Standard TOP-008 – that is, to specify the minimum set of tools necessary to monitor the bulk electric system and maintain operator situational awareness. The new standard shall apply to both RCs and TOPs[28]:

PR1. Reliability Monitoring and Analysis Tools (Reliability Toolbox). Each reliability coordinator and transmission operator shall have adequate monitoring and analysis tools to maintain situational awareness for his/her respective areas of responsibility.[29] The following monitoring and analysis tools are mandatory:

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[28] Proposed requirements are designated "PR," and proposed measures are designated "PM."

[29] RTBPTF recognizes that differences will arise naturally between TOPs and RCs in their use of the tools. For example, the definition of the wide-area boundary (for RCs) and the "local"

- Alarm tools
- Telemetry data systems
- Network topology processor
- State estimator
- Contingency analysis

RTBPTF recommends the following measure for the requirement stated above:

PM1. Each reliability coordinator and transmission operator shall have and provide upon request evidence that shall include, but is not limited to, the following:

- Documentation from suppliers
- Operating and support staff training documents and users' guides
- Tool maintenance and support documents
- Logs/records of tool availability and tool output results
- Displays and/or visualization tools that show data from these tools
- Other equivalent evidence to show that it has the monitoring analysis tools in accordance with Requirement PR1 and that the tools are functioning and being used as planned

Rationale

Existing NERC reliability standards require the use of monitoring and analysis tools to aid operators in maintaining situational awareness of the bulk electric system. However, these standards do not explicitly require specific tools and are not globally applicable to all users of such tools. For example, Standard TOP-008 (Response to Transmission Limit Violations) exists, "[t]o ensure Transmission Operators take actions to mitigate SOL and IROL violations."[30] Requirement R4 of this standard states, "[t]he Transmission Operator shall have ***sufficient*** [emphasis added] information and ***analysis tools*** [emphasis added] to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation." This standard applies only to transmission operators.

Similarly, standard IRO-002 (Reliability Coordination – Facilities) states, "Reliability Coordinators need information, ***tools*** [emphasis added] and other capabilities to perform their responsibilities." Requirement R7 of this standard states, "[e]ach Reliability Coordinator shall have ***adequate analysis tools***

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transmission system (for TOPs) will have implications for the scope of the network model that each relies upon.

[30] Quotation taken from the purpose statement in section A.3 of NERC Reliability Standard TOP-008-1

[emphasis added] such as state estimation, pre and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays." Requirement R9 states, "[e]ach Reliability Coordinator shall control its Reliability Coordinator ***analysis tools*** [emphasis added], including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of ***analysis tool*** [emphasis added] outages." This standard applies only to reliability coordinators.

RTBPTF believes that Standard TOP-006 is the most appropriate standard in which to incorporate the mandatory tools requirement because this standard is applicable to both RCs and TOPs. In addition, Standard TOP-006 clearly focuses on ensuring that "critical reliability parameters are monitored in real-time."[31] To ensure that critical reliability parameters are monitored in real time, NERC reliability standards must specify a minimum set of tools. The Reliability Toolbox comprises those tools.

RTBPTF believes that the "analysis tools" prescribed by both Standard IRO-002 (Requirement R7) and Standard TOP-008 (Requirement R4) refer to the same set of monitoring and analysis tools even allowing for the natural differences in the use of these tools by TOPs and RCs arising from their different responsibilities as specified by the NERC Functional Model. Locating the Reliability Toolbox requirement in Standard TOP-006, which applies to both reliability coordinators and transmission operators, mandates a uniform minimum set of tools for both RCs and TOPs. It also clarifies and makes specific the term "sufficient information and analysis tools" in Standard TOP-008 (Requirement R4) and the term "adequate analysis tools" in Standard IRO-002 (Requirement R7).

Applicability Statement

Even though the Reliability Toolbox is recommended to be mandatory for only RCs and TOPs, the task force realizes that other entities such as transmission owners and balancing authorities use some or all of these tools as well. In the particular technical sections of this report addressing the individual tools, RTBPTF recommends specific requirements for the use, availability, and performance of these tools, and further recommends in those sections that these requirements apply to all users of the tools. Specifically, any entity not registered in the NERC Functional Model as an RC or a TOP, but that uses any of these tools to support or complement their RC's or TOP's ability to operate the bulk electric system reliably in accordance with formal agreements, contracts, or previously established practices or procedures, shall also be subject to compliance with the specific requirements for the tools.

[31] Quotation taken from the purpose statement in section A.3 of NERC Reliability Standard TOP-006-1.

Section 1.0
Real-Time Data Collection

Introduction

Collecting real-time data on power system status is the first and most elementary step in the complex process of developing the information that electric system operators need to maintain situational awareness. Real-time reliability tools such as the state estimator and contingency analysis can only provide results that accurately represent current and potential reliability problems if these tools have real-time power-flow and voltage values and status data for other elements included in their models. The accuracy of the information that real-time reliability tools provide depends on the accuracy of the data supplied to the tools.

The quality of the results that real-time reliability tools produce is also influenced by the breadth and depth of the portion of the bulk electric system for which real-time data are collected, relative to the breadth and depth of the relevant reliability entity's area of responsibility. Thus, how we define the elements that constitute the bulk electric system is very important for the information that operators reply to for situational awareness.

To assess current industry practice regarding real-time data collection, the Real-Time Data Collection portion of the Real-Time Tools Survey focused on telemetry, ICCP-specific, and miscellaneous data (weather, fault locator, and high-speed sampled data). The survey findings for each type of data are presented in the Sections 1.1-1.3. These sections are summarized below:

- **Section 1.1, Telemetry Data** — This section summarizes the types of real- and near-real-time data collected by telemetry systems for use in EMSs to monitor the bulk electric system. Telemetry data are typically status and analog values that are updated continuously in real or near-real time. These data allow operators to determine, in real- or near-real time, the state of the interconnected bulk electric system. For operators to reliably run the system in a coordinated manner under normal and abnormal conditions, telemetry data systems must function with a high degree of availability. Therefore, tools and practices related to telemetry data availability are important for system reliability and operator situational awareness.

  Section 1.1 also addresses the conversion of real-time data into useful information for operators. The *FERC Staff Assessment* of NERC's proposed reliability standards[1] states:

[1] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp. Referred to in this document as the *FERC Staff Assessment*.

> … while the requirements identify the data to be gathered, they fail to describe the tools necessary to turn that data into critical reliability parameters, i.e., system capability or contingency analysis, which are required to achieve situational awareness. Reliability Coordinators, Transmission Operators, and Balancing Authorities must be aware of the status of their respective systems, and such situational awareness cannot be obtained by viewing massive amounts of raw data.

RTBPTF agrees that the NERC standards generally fail to describe the tools necessary for monitoring “critical reliability parameters.” Section 1.1 gives a snapshot of the types of telemetry data currently being collected throughout the industry, describes the Real-Time Tools Survey findings related to telemetry data, and discusses the tools necessary to comply with NERC standards that require reliability entities to “monitor” specific data and bulk electric system elements and parameters.

Section 1.1 also explores the definition of bulk electric system elements.

- **Section 1.2, ICCP-Specific Data** — ICCP is a standard data-exchange format widely used in the electric utility industry to communicate information among operating entities. The NERC ISN uses ICCP for data exchange among reliability coordinators. Several intra-regional and intra-company networks also use this protocol to provide data to RCs from operating entities within the RC’s footprint. Section 1.2 addresses the management of and methodology for ICCP data exchange and examines issues and practices that affect the adequacy, quality, and timeliness of ICCP data supplied to real-time tools that analyze bulk electric system reliability.

- **Section 1.3, Miscellaneous Data** — Miscellaneous data are used by real-time applications/tools that may not be supported by basic SCADA and/or ICCP systems. Section 1.3 addresses: 1) meteorological data, such as from commercial weather services, 2) fault locater data, such as from protective relays that can calculate the distance from the relay location to the location of a transmission-line fault, and 3) high-speed sampled data, such as from sequence-of-event recorders and phasor monitoring units (PMUs).

Significance to the August 14, 2003 Blackout

The U.S.-Canada Power System Outage Task Force analysis of the August 14, 2003[2] blackout identified the failure of the interconnected grid's reliability organizations to provide effective real-time diagnostic support as one cause of the blackout. Specifically, the reliability data that MISO received via the East Central Area Reliability Council (ECAR) data network and other data links were not mapped so that MISO's state estimator could be automatically informed of the status change in key transmission lines.

RTBPTF Recommendations for New Reliability Standards

In Sections 1.1 through 1.3, RTBPTF recommends that several new requirements be added to existing standards:

- Each RC must compile and maintain a list of all bulk electric system elements within its area of responsibility.
- New requirements and measures must be added pertaining to RC monitoring of the bulk electric system.
- Data exchange standards must be developed to address change management and coordination, data access restrictions, naming conventions, joint testing and data checkout, system interoperability, quality codes, and dispute resolution.
- Standards must be developed for data availability, and a process must be developed for trouble resolution and escalation.
- A new requirement must be developed addressing the importance of weather data for situational awareness and real-time operational capabilities. Specifically, operators must be provided dynamically updated real-time and forecasted weather data so that they can readily determine current and near-term weather conditions that might affect how they need to monitor or operate their systems.

[2] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. Referred to in this document as the *Outage Task Force Final Blackout Report.*

Section 1.1
Telemetry Data

Definition

Telemetry data are status and analog values originating from conventional SCADA/EMS or equivalent systems (telemetry data systems) and are updated continuously in real-time or near-real-time operation. These data may come directly from SCADA system(s) or from direct connection (ICCP, ISN, etc.) to SCADA systems operated by others.

Background

Telemetry data from direct connections to internal systems (i.e., from SCADA/EMS or equivalent systems) and/or direct connections to external systems operated by others (i.e., ICCP data links) allow operators to determine, in real or near-real time, the state of the interconnected bulk electric system. To reliably operate the system in a coordinated manner under normal and abnormal conditions as defined in NERC standards, operators must have telemetry data and corresponding telemetry data systems available. Telemetry data and systems are essential to NERC‘s mandated real-time monitoring capability; tools and practices related to telemetry data availability are important for system reliability and operator situational awareness.

The *FERC Staff Assessment* of NERC's proposed reliability standards[3] states:

> … while the requirements identify the data to be gathered, they fail to describe the tools necessary to turn that data into critical reliability parameters, i.e., system capability or contingency analysis, which are required to achieve situational awareness. Reliability Coordinators, Transmission Operators, and Balancing Authorities must be aware of the status of their respective systems, and such situational awareness cannot be obtained by viewing massive amounts of raw data.

RTBPTF agrees with the FERC staff conclusions above. NERC standards generally fail to describe the necessary tools for monitoring "critical reliability parameters."

The telemetry data section of the Real-Time Tools Survey was designed to take a snapshot of current availability of certain types of telemetry data throughout the

[3] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

industry. The Real-Time Tools Survey also determined what telemetry data are available from bulk electric system elements currently used by reliability entities. This section of the report describes the survey findings related to telemetry data, discusses the tools necessary to comply with NERC standards that involve use of telemetry data, and presents RTBPTF's recommended requirements for using these tools. This section also discusses issues related to the definition and the interpretation of the term "bulk electric system." RTBPTF reinforces the importance of the resolution of this definition as it affects task force's recommendations. RTBPTF recognizes that entities cannot be expected to use specific tools to monitor the "bulk electric system" without stipulating which components of the bulk electric system are to be monitored or require telemetry data.

Summary of Findings

The subsections below summarize the Real-Time Tools Survey responses regarding telemetry data for generators, transmission lines and transformers, and substation switching devices, as well as telemetry data maintenance and support practices.

Most survey respondents (97 percent, 58 out of 60) indicated that their organizations use telemetry data. An overwhelming majority (96 percent, 54 out of 57) of respondents that have operational telemetry data systems rate the availability of telemetry data as "essential" for situational awareness. This concurrence of opinion is uniform across the types of entities that participated in the survey (RCs, TOPs, BAs). Respondents expressed most concern about the quantity of data available from their systems. For example, one respondent said that "a large network [model] and lack of real time telemetry is one of the biggest issues" with which that respondent deals in "real time network modeling."

Most respondents reported that they receive telemetry data through a combination of direct connection to a SCADA/EMS system (89 percent, 51 out of 57) and/or direct ICCP connections to other utilities/systems (84 percent, 48 out of 57). The applications most commonly reported as using telemetry data were the network topology processor (70 percent, 40 out of 57 respondents), state estimator (77 percent, 44 out of 57), alarm tools (98 percent, 56 out of 57), and visualization tools (81 percent, 46 out of 57).

Generator Telemetry Data

This subsection summarizes the findings for telemetry data from generating units. All respondents reported that they have some form of generator telemetry data available; 95 percent of respondents rated the availability of generator data "essential" to enhancing situational awareness.

Generator Data within Respondent's Area of Responsibility

Respondents were asked to quantify the telemetry data ("all," "most," "some," or "none") they receive from central station generating units within their areas of responsibility. Table 1.1-1 summarizes the responses. The number of respondents selecting the answer listed at the top of a column is given followed by the total number of respondents and the equivalent percentage of respondents (i.e., 36/55=65% indicates that 36 out of 55 respondents or 65 percent of respondents chose this answer). Data are presented in this manner throughout this section.

Type of Generator Telemetry Data	What Telemetry Data do You Receive for Central Station Generating Units Within Your Area of Responsibility?			
	All	Most	Some	None
Total net plant output (MW and Mvar)	36/55=65 %	10/55=18 %	7/55=13 %	2/55=4 %
Unit connection status	36/57=63 %	17/57=30 %	3/57=5 %	1/57=2 %
Unit status (Offline, outage, base load, regulating, etc.)	27/55=49 %	16/55=29 %	9/55=16 %	3/55=5 %
Unit output at the generator terminals (MW and Mvar)	27/56=48 %	23/56=41 %	5/56=9 %	1/56=2 %
Unit-connected station service loads (MW and Mvar)	8/57=14 %	20/57=35 %	19/57=33 %	10/57=18 %
Common station service loads (MW and Mvar)	8/56=14 %	19/56=34 %	22/56=39 %	7/56=13 %
Net unit output at the high side of the step-up transformer (MW and Mvar)	21/57=37 %	18/57=32 %	16/57=28 %	2/57=4 %
Operating Limits (MW)	19/57=33 %	14/57=25 %	11/57=19 %	13/57=23 %
Operating Limits (Mvar)	11/57=19 %	8/57=14 %	8/57=14 %	30/57=53 %
Automatic Voltage Regulator (AVR) Status	3/57=5 %	8/57=14 %	16/57=28 %	30/57=53 %
Stabilizer Status	4/53=8 %	3/53=6 %	7/53=13 %	39/53=74 %
Ramp Rate Capability	10/56=18 %	6/56=11%	14/56=25 %	26/56=46 %
Governor Status	1/53=2 %	1/53=2 %	8/53=15 %	43/53=81 %

Table 1.1-1 — Generator Telemetry Data Within Respondents' Areas of Responsibility — All Respondents

Table 1.1-1 shows that generator total net output (MW and Mvar) and corresponding generator status are the most common forms of generator telemetry data received by respondents within their areas of responsibility. The survey results also reveal that the majority of entities do not receive MW and/or Mvar operating limits. RTBPTF infers that respondents may be using static MW and/or Mvar generator operating limits in lieu of telemetered data. The majority of respondents do not receive other forms of generator telemetry data [i.e., automatic voltage regulator (AVR) status, stabilizer status, etc.] from their telemetry data systems. RC responses to the questions listed in Table 1.1-1 are broken out in Table 1.1-2. The percentages for RC responses are similar to those for all respondents.

Type of Generator Telemetry Data	What Telemetry Data do You Receive for Central Station Generating Units Within Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
Total net plant output (MW and Mvar)	13/17=76 %	2/17=12 %	2/17=12 %	0/17=0 %
Unit connection status	11/18=61 %	5/18=28 %	2/18=11 %	0/18=0 %
Unit status (Offline, outage, base load, regulating, etc.)	9/17=53 %	3/17=18 %	4/17=24 %	1/17=6 %
Unit output at the generator terminals (MW and Mvar)	9/18=50 %	7/18=39 %	2/18=11 %	0/18=0 %
Unit-connected station service loads (MW and Mvar)	1/18=6 %	5/18=28 %	8/18=44 %	4/18=22 %
Common station service loads (MW and Mvar)	1/18=6 %	5/18=28 %	9/18=50 %	3/18=17 %
Net unit output at the high side of the step-up transformer (MW and Mvar)	4/18=22 %	7/18=39 %	7/18=39 %	0/18=0 %
Operating Limits (MW)	6/18=33 %	3/18=17 %	5/18=28 %	4/18=22 %
Operating Limits (Mvar)	4/18=22 %	2/18=11 %	3/18=17 %	9/18=50 %
AVR Status	0/18=0 %	5/18=28 %	9/18=50 %	4/18=22 %
Stabilizer Status	2/17=12 %	2/17=12 %	3/17=18 %	10/17=59 %
Ramp Rate Capability	2/18=11 %	3/18=17 %	4/18=22 %	9/18=50 %
Governor Status	0/17=0 %	0/17=0 %	3/17=18 %	14/17=82 %

Table 1.1-2 — Generator Telemetry Data within Respondents' Areas of Responsibility — RCs only

Generator Data for Adjacent Areas

The survey asked respondents to quantify the telemetry data ("all," "most," "some," or "none") they receive for central station generating units from areas adjacent to the respondents' areas of responsibility. Table 1.1-3 summarizes the responses.

Type of Generator Telemetry Data	What Telemetry Data do You Receive for Central Station Generating Units from Areas Adjacent to Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
Total net plant output (MW and Mvar)	5/55=9 %	4/55=7 %	28/55=51 %	18/55=33 %
Unit connection status	2/56=4 %	5/56=9 %	32/56=57 %	17/56=30 %
Unit status (Offline, outage, base load, regulating, etc.)	1/55=2 %	2/55=4 %	18/55=33 %	34/55=62 %
Unit output at the generator terminals (MW and Mvar)	2/56=4 %	4/56=7 %	28/56=50 %	22/56=39 %
Unit-connected station service loads (MW and Mvar)	0/56=0 %	2/56=4 %	12/56=21 %	42/56=75 %
Common station service loads (MW and Mvar)	0/56=0 %	2/56=4 %	11/56=20 %	43/56=77 %
Net unit output at the high side of the step-up transformer (MW and Mvar)	2/56=4 %	3/56=5 %	28/56=50 %	23/56=41 %
Operating Limits (MW)	1/55=2 %	1/55=2 %	4/55=7 %	49/55=89 %
Operating Limits (Mvar)	1/56=2 %	1/56=2 %	2/56=4 %	52/56=93 %
AVR Status	0/55=0 %	0/55=0 %	2/55=4 %	53/55=96 %
Stabilizer Status	0/55=0 %	0/55=0 %	2/55=4 %	53/55=96 %
Ramp Rate Capability	0/55=0 %	0/55=0 %	3/55=5 %	52/55=95 %
Governor Status	0/55=0 %	0/55=0 %	0/55=0 %	55/55=100 %

Table 1.1-3 — Generator Telemetry Data in Areas Adjacent to Respondents' Areas of Responsibility — All Respondents

Table 1.1-3 shows that the vast majority of respondents do not receive generator telemetry data from areas adjacent to their areas of responsibility. These responses are explained by the lack of specific criteria for the number of adjacent-area telemetry data needed to fulfill monitoring requirements for a "wide-area" view. Table 1.1-4 breaks out RC responses to the questions in Table 1.1-3. The percentages for RC responses are similar to those for all respondents.

Type of Generator Telemetry Data	What Telemetry Data do You Receive for Central Station Generating Units from Areas Adjacent to Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
Total net plant output (MW and Mvar)	2/17=12 %	3/17=18 %	8/17=47 %	4/17=24 %
Unit connection status	2/18=11 %	5/18=28 %	10/18=56 %	1/18=6 %
Unit status (Offline, outage, base load, regulating, etc.)	1/17=6 %	2/17=12 %	8/17=47 %	6/17=35 %
Unit output at the generator terminals (MW and Mvar)	2/18=11 %	4/18=22 %	10/18=56 %	2/18=11 %
Unit-connected station service loads (MW and Mvar)	0/18=0 %	2/18=11 %	5/18=28 %	11/18=61 %
Common station service loads (MW and Mvar)	0/18=0 %	2/18=11 %	6/18=33 %	10/18=56 %
Net unit output at the high side of the step-up transformer (MW and Mvar)	2/18=11%	2/18=11 %	10/18=56 %	4/18=22 %
Operating Limits (MW)	1/18=6 %	1/18=6 %	2/18=11 %	14/18=78 %
Operating Limits (Mvar)	1/18=6 %	1/18=6 %	1/18=6 %	15/18=83 %
AVR Status	0/17=0 %	0/17=0 %	1/17=6 %	16/17=94 %
Stabilizer Status	0/17=0 %	0/17=0 %	1/17=6 %	16/17=94 %
Ramp Rate Capability	0/17=0 %	0/17=0 %	0/17=0 %	17/17=100 %
Governor Status	0/17=0 %	0/17=0 %	0/17=0 %	17/17=100 %

Table 1.1-4 — Generator Telemetry Data in Areas Adjacent to Respondents' Areas of Responsibility — RCs only

Generator Data for Other Units Affecting Respondent's Area of Responsibility

The survey asked respondents to quantify the telemetry data ("all," "most," "some," or "none") they receive for other types of generators that affect their area of responsibility [i.e., independent power producers (IPPs), distributed generation]. Table 1.1-5 summarizes the responses. The table shows that the majority of respondents do not receive generator telemetry data from other units that may affect their areas of responsibility. Note that IPPs may have a significant impact on an entity's area of responsibility.

Type of Generator Telemetry Data	Do You Receive Real-Time Data for Other Units Affecting Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
IPPs	21/55=38 %	10/55=18 %	11/55=20 %	13/55=24 %
Distributed generation at cogeneration or customer locations	6/57=11 %	10/57=18 %	18/57=32 %	23/57=40 %
Customer loads participating in generation ancillary service	6/55=11 %	6/55=11 %	4/55=7 %	39/55=71 %
Generating plants beyond adjacent areas of your responsibility	2/57=4 %	5/57=9 %	13/57=23 %	7/57=65 %

Table 1.1-5 — Other Types of Generator Telemetry Data from Areas Adjacent to Respondents' Areas of Responsibility

Special or Calculated Generator Data

The survey asked respondents to quantify the telemetry data ("all," "most," "some," or "none") received for any special, real-time calculation for generating units in or adjacent to their areas of responsibility. Table 1.1-6 summarizes the responses Respondents do not commonly receive these types of data.

Special Generator Telemetry Data Type	Do You Use Any Special, Real-Time Calculation for Generating Units In or Adjacent to Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
Substitute for any values at generating units not available by SCADA	1/51=2 %	1/51=2 %	19/51=37 %	30/51=59 %
Supplemental available data (such as reserve levels, hours of fuel, etc.)	3/53=6 %	1/53=2 %	11/53=21 %	38/53=72 %

Table 1.1-6 — Generator Telemetry Data for Special Real-Time Calculations In or Adjacent to Respondents' Areas of Responsibility

Transmission-Line Telemetry Data

This subsection summarizes survey findings regarding telemetry data for transmission lines. All respondents have some form of transmission-line telemetry data available, and 96 percent rated availability of transmission-line data as "essential" for enhancing situational awareness.

Transmission-Line Data within Respondents' Areas of Responsibility

The survey asked respondents to quantify the telemetry data ("all," "most," "some," or "none") they receive for transmission lines [345-765 kilovolt (kV)] within their areas of responsibility. Table 1.1-7 summarizes the responses.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (345-765 kV) Within Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
MW and Mvar flow on at least one end	38/52=73 %	5/52=10 %	1/52=2 %	8/52=15 %
MW and Mvar flow on both ends	31/53=58 %	13/53=25 %	0/53=0 %	9/53=17 %
Current flow magnitude (Amperes) at either end	8/51=16 %	6/51=12 %	7/51=14 %	30/51=59 %
Current flow phase angle (degrees) at either end	0/51=0 %	2/51=4 %	5/51=10 %	44/51=86 %
Megavoltamperes (MVA) flow at either end	4/52=8 %	5/52=10 %	3/52=6 %	40/52=77 %
Real-time operating limits determined by substation equipment/systems	10/52=19 %	1/52=2 %	5/52=10 %	36/52=69 %
Line connection status	37/52=71 %	6/52=12 %	1/52=2 %	8/52=15 %
Line availability status (Tagged out, damaged, grounded, etc.)	18/51=35 %	1/51=2 %	4/51=8 %	28/51=55 %
kV on at least one end	36/52=69 %	7/52=13 %	1/52=2 %	8/52=15 %
kV on both ends	27/52=52 %	11/52=21 %	4/52=8 %	10/52=19 %

Table 1.1-7 — Telemetry Data for Transmission Lines (345-765 kV) Within Respondents' Areas of Responsibility — All Respondents

Table 1.1-7 shows that MW and Mvar flows, line connection status, and kV on at least one end are the most common forms of transmission-line telemetry data that respondents receive for 345 to 765-kV transmission lines within their areas of responsibility. Respondents report that their telemetry data systems provide either "all" or "most" of these data. The survey results also reveal that the majority of respondents do not receive MW and/or Mvar operating limit data. RTBPTF infers that respondents may be using static MW and/or Mvar transmission-line operating limits in lieu of telemetered data. The majority of respondents do not receive other forms of transmission-line telemetry data (i.e., current flow magnitude, phase angle measurements) within their areas of responsibility. Table 1.1-8 summarizes responses to this survey question from RCs only regarding transmission-line data. The percentages for reliability coordinators' responses are similar to those for all respondents.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (345-765 kV) Within Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
MW and Mvar flow on at least one end	13/17=76 %	3/17=18 %	0/17=0 %	1/17=6 %
MW and Mvar flow on both ends	10/17=59 %	7/17=41 %	0/17=0 %	0/17=0 %
Current flow magnitude (Amperes) at either end	4/16=25 %	0/16=0 %	3/16=19 %	9/16=56 %
Current flow phase angle (degrees) at either end	0/16=0 %	0/16=0 %	2/16=13 %	14/16=88 %
MVA flow at either end	0/17=0 %	2/17=12 %	2/17=12 %	13/17=76 %
Real-time operating limits determined by substation equipment/systems	4/17=24 %	1/17=6 %	4/17=24 %	8/17=47 %
Line connection status	12/17=71 %	5/17=29 %	0/17=0 %	0/17=0 %
Line availability status (tagged out, damaged, grounded, etc.)	6/16=38 %	0/16=0 %	2/16=13 %	8/16=50 %
kV on at least one end	10/17=59 %	5/17=29 %	1/17=6 %	1/17=6 %
kV on both ends	8/17=47 %	5/17=29 %	3/17=18 %	1/17=6 %

Table 1.1-8 — Telemetry Data for Transmission Lines (345-765 kV) Within Respondents' Areas of Responsibility — RCs only

The survey asked respondents to quantify telemetry data ("all," "most," "some," or "none") they receive for transmission lines (100 to 230 kV) within their areas of responsibility. Table 1.1-9 summarizes the responses. For 100- to 230-kV voltage transmission lines, telemetry data for MW and Mvar flows, line connection status, and kV on at least one end are the most common telemetry data that respondents receive within their areas of responsibility although these data are not as common as data for 345- to 765-kV transmission lines. For 345- to 765-kV transmission lines, the majority of respondents do not receive data on MW and/or Mvar operating limits. RTBPTF infers that entities may be using static MW and/or Mvar transmission line operating limits in lieu of telemetered data.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (100-230 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	29/56=52 %	24/56=43 %	3/56=5 %	0/56=0 %
MW and Mvar flow on both ends	13/57=23 %	32/57=56 %	12/57=21 %	0/57=0 %
Current flow magnitude (Amperes) at either end	9/55=16 %	10/55=18 %	11/55=20 %	25/55=45 %
Current flow phase angle (degrees) at either end	0/54=0 %	0/54=0 %	8/54=15 %	46/54=85 %
MVA flow at either end	12/55=22 %	5/55=9 %	1/55=2 %	37/55=67 %
Real-time operating limits determined by substation equipment/systems	9/56=16 %	5/56=9 %	11/56=20 %	31/56=55 %
Line connection status	30/56=54 %	19/56=34 %	3/56=5 %	4/56=7 %
Line availability status (Tagged out, damaged, grounded, etc.)	19/55=35 %	12/55=22 %	1/55=2 %	23/55=42 %
kV on at least one end	32/55=58 %	19/55=35 %	4/55=7 %	0/55=0 %
kV on both ends	13/57=23 %	30/57=53 %	13/57=23 %	1/57=2 %

Table 1.1-9 — Telemetry Data for 100- to 230-kV Transmission Lines Within Respondents' Areas of Responsibility

Respondents were also asked to quantify telemetry data ("all," "most," "some," or "none") they receive for transmission lines less than 100 kV within their areas of responsibility. Table 1.1-10 summarizes the responses. The majority of respondents do not receive telemetry data for less-than-100-kV transmission lines within their areas of responsibility.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (<100 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	16/56=29 %	24/56=43 %	14/56=25 %	2/56=4 %
MW and Mvar flow on both ends	10/57=18 %	17/57=30 %	25/57=44 %	5/57=9 %
Current flow magnitude (Amperes) at either end	5/55=9 %	14/55=25 %	8/55=15 %	28/55=51 %
Current flow phase angle (degrees) at either end	0/54=0 %	0/54=0 %	1/54=2 %	53/54=98 %
MVA flow at either end	5/56=9 %	5/56=9 %	6/56=11 %	40/56=71 %
Real-time operating limits determined by substation equipment/systems	8/57=14 %	2/57=4 %	6/57=11 %	41/57=72 %
Line connection status	17/56=30 %	24/56=43 %	9/56=16 %	6/56=11 %
Line availability status (Tagged out, damaged, grounded, etc.)	16/56=29 %	8/56=14 %	4/56=7 %	28/56=50 %
kV on at least one end	20/56=36 %	20/56=36 %	15/56=27 %	1/56=2 %
kV on both ends	7/57=12 %	17/57=30 %	26/57=46 %	7/57=12 %

Table 1.1-10 — Telemetry Data for less-than-100-kV Transmission Lines Within Respondents' Areas of Responsibility

Transmission-Line Data for Adjacent Areas

The survey asked respondents to quantify telemetry data (“all,” “most,” “some,” or “none”) they receive for transmission lines (345 to 765 kV) in areas adjacent to their areas of responsibility. Table 1.1-11 summarizes the responses.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (345-765 kV) From Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	10/56=18 %	12/56=21 %	26/56=46 %	8/56=14 %
MW and Mvar flow on both ends	5/56=9 %	3/56=5 %	30/56=54 %	18/56=32 %
Current flow magnitude (Amperes) at either end	3/54=6 %	1/54=2 %	11/54=20 %	39/54=72 %
Current flow phase angle (degrees) at either end	0/54=0 %	0/54=0 %	2/54=4 %	52/54=96 %
MVA flow at either end	1/55=2 %	2/55=4 %	8/55=15 %	44/55=80 %
Real-time operating limits determined by substation equipment/systems	3/55=5 %	0/55=0 %	4/55=7 %	48/55=87 %
Line connection status	10/56=18 %	6/56=11 %	24/56=43 %	16/56=29 %
Line availability status (Tagged out, damaged, grounded, etc.)	5/56=9 %	1/56=2 %	5/56=9 %	45/56=80 %
kV on at least one end	9/56=16 %	9/56=16 %	26/56=46 %	12/56=21 %
kV on both ends	4/56=7 %	4/56=7 %	23/56=41 %	25/56=45 %

Table 1.1-11 — Telemetry Data for Transmission Lines (345-765 kV) in Areas Adjacent to Respondents’ Areas of Responsibility — All Respondents

Table 1.1-11 shows that the majority of respondents do not receive transmission-line telemetry data from adjacent areas. This may be explained by the lack of specific criteria for the adjacent-area telemetry data needed to fulfill monitoring requirements for “wide-area” view. Table 1.1-12 shows responses for RCs only regarding transmission-line telemetry data from adjacent areas. The percentages for RCs’ responses are similar to those for all respondents.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (345-765 kV) from Areas Adjacent to Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
MW and Mvar flow on at least one end	6/18=33 %	9/18=50 %	3/18=17 %	0/18=0 %
MW and Mvar flow on both ends	4/18=22 %	7/18=39 %	7/18=39 %	0/18=0 %
Current flow magnitude (Amperes) at either end	1/17=6 %	3/17=18 %	3/17=18 %	10/17=59 %
Current flow phase angle (degrees) at either end	0/17=0 %	0/17=0 %	0/17=0 %	17/17=100 %
MVA flow at either end	1/18=6 %	2/18=11 %	1/18=6 %	14/18=78 %
Real-time operating limits determined by substation equipment/systems	2/18=11 %	4/18=22 %	5/18=28 %	7/18=39 %
Line connection status	8/18=44 %	6/18=33 %	3/18=17 %	1/18=6 %
Line availability status (Tagged out, damaged, grounded, etc.)	4/16=25 %	3/16=19 %	1/16=6 %	8/16=50 %
KV on at least one end	8/18=44 %	6/18=33 %	4/18=22 %	0/18=0 %
KV on both ends	4/18=22 %	5/18=28 %	8/18=44 %	1/18=6 %

Table 1.1-12 — Telemetry Data for Transmission Lines (345-765 kV) from Adjacent Areas — RCs Only

Respondents were asked to quantify telemetry data they receive (“all,” “most,” “some,” or “none”) for transmission lines (100-230 kV) from areas adjacent to their areas of responsibility. Table 1.1-13 summarizes the responses. The majority of respondents do not receive telemetry data for transmission lines (100-230 kV) in adjacent areas.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (100-230 kV) from Areas Adjacent to Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
MW and Mvar flow on at least one end	7/55=13 %	7/55=13 %	34/55=62 %	7/55=13 %
MW and Mvar flow on both ends	3/55=5 %	5/55=9 %	31/55=56 %	16/55=29 %
Current flow magnitude (Amperes) at either end	2/52=4 %	0/52=0 %	11/52=21 %	39/52=75 %
Current flow phase angle (degrees) at either end	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
MVA flow at either end	2/52=4 %	0/52=0 %	9/52=17 %	41/52=79 %
Real-time operating limits determined by substation equipment/systems	1/53=2 %	1/53=2 %	6/53=11 %	45/53=85 %
Line connection status	9/54=17 %	3/54=6 %	30/54=56 %	12/54=22 %
Line availability status (Tagged out, damaged, grounded, etc.)	3/54=6 %	2/54=4 %	6/54=11 %	43/54=80 %
KV on at least one end	6/54=11 %	4/54=7 %	32/54=59 %	12/54=22 %
KV on both ends	2/55=4 %	5/55=9 %	29/55=53 %	19/55=35 %

Table 1.1-13 — Telemetry Data for Transmission Lines (100-230 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Respondents were asked to quantify telemetry data they receive ("all," "most," "some," or "none") for transmission lines (less than 100 kV) from areas adjacent to their areas of responsibility. Table 1.1-14 summarizes the responses. Most respondents received no telemetry data for transmission lines less than 100 kV in adjacent areas.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (<100 kV) from Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	0/55=0 %	2/55=4 %	24/55=44 %	29/55=53 %
MW and Mvar flow on both ends	0/55=0 %	1/55=2 %	17/55=31 %	37/55=67 %
Current flow magnitude (Amperes) at either end	0/53=0 %	0/53=0 %	4/53=8 %	49/53=92 %
Current flow phase angle (degrees) at either end	0/53=0 %	0/53=0 %	0/53=0 %	53/53=100 %
MVA flow at either end	0/53=0 %	0/53=0 %	2/53=4 %	51/53=96 %
Real-time operating limits determined by substation equipment/systems	0/54=0 %	1/54=2 %	2/54=4 %	51/54=94 %
Line connection status	1/55=2 %	2/55=4 %	20/55=36 %	32/55=58 %
Line availability status (Tagged out, damaged, grounded, etc.)	1/54=2 %	0/54=0 %	4/54=7 %	49/54=91 %
KV on at least one end	0/54=0 %	3/54=6 %	20/54=37 %	31/54=57 %
KV on both ends	0/54=0 %	0/54=0 %	19/54=35 %	35/54=65 %

Table 1.1-14 — Telemetry Data for Transmission Lines (less than 100 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Transmission-Line Data — Special or Calculated

The survey asked respondents to quantify telemetry data they receive ("all," "most," "some," or "none") for any special, real-time calculation for transmission lines in or adjacent to their areas of responsibility. Table 1.1-15 summarizes the responses. The majority of respondents do not receive special or calculated transmission-line telemetry data.

Special Transmission-Line Telemetry Data Type	Do You Use Any Special, Real-Time Calculation for Transmission Lines in or Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Special substitution for any values on lines not available by SCADA	7/55=13 %	1/55=2 %	19/55=35 %	28/55=51 %
Terminal angular separation (degrees)	2/53=4 %	0/53=0 %	4/53=8 %	47/53=89 %
Supplemental available data (such as line temperature, time in overload, etc)	1/52=2 %	2/52=4 %	5/52=10 %	44/52=85 %

Table 1.1-15 — Telemetry Data for Special, Real-Time Calculations for Transmission Lines In or Adjacent to Respondents' Areas of Responsibility

Transmission Transformer Telemetry Data

This subsection summarizes findings for transmission transformer telemetry data. All respondents have some form of transmission transformer telemetry data available; 85 percent rated the availability of transmission transformer telemetry data as “essential” for enhancing their situational awareness.

Transmission Transformer Data within Respondents’ Areas of Responsibility

The survey asked respondents to quantify telemetry data they receive (“all,” “most,” “some,” or “none”) for transmission transformers (at various voltage levels) within their areas of responsibility. Table 1.1-16, Table 1.1-17, and Table 1.1-18 summarize the responses. It is interesting to note that the majority of respondents do not receive telemetry data for transmission transformers within their areas of responsibility even in the highest voltage range (i.e., 345-765 kV). As the voltage level decreases, even fewer telemetry data are received.

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (345-765 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Tap position	14/52=27 %	9/52=17 %	11/52=21 %	11/52=21 %
High-side MW and Mvars	21/53=40 %	9/53=17 %	14/53=26 %	9/53=17 %
High-side kV	27/53=51 %	9/53=17 %	10/53=19 %	7/53=13 %
Low-side MW and Mvars	21/53=40 %	12/53=23 %	13/53=25 %	7/53=13 %
Low-side kV	22/53=42 %	13/53=25 %	11/53=21 %	7/53=13 %
Oil temperature	7/51=14 %	4/51=8 %	12/51=24 %	28/51=55 %
Winding hot-spot temperatures	8/51=16 %	3/51=6 %	12/51=24 %	28/51=55 %
Ambient temperature	1/52=2 %	2/52=4 %	15/52=29 %	34/52=65 %
Cooling-system status	6/50=12 %	4/50=8 %	9/50=18 %	31/50=62 %
Combustible gas density	5/50=10 %	1/50=2 %	6/50=12 %	38/50=76 %
Real-time operating limits determined by substation equipment/systems	8/53=15 %	1/53=2 %	2/53=4 %	42/53=79 %
Voltage regulation control status	9/51=18 %	3/51=6 %	6/51=12 %	33/51=65 %

Table 1.1-16 — Telemetry Data for Transmission Transformers (345-765 kV) within Respondents’ Areas of Responsibility

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (100-230 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Tap position	13/55=24 %	12/55=22 %	20/55=36 %	10/55=18 %
High-side MW and Mvars	16/57=28 %	15/57=26 %	21/57=37 %	5/57=9 %
High-side kV	23/57=40 %	20/57=35 %	12/57=21 %	2/57=4 %
Low-side MW and Mvars	22/57=39 %	17/57=30 %	17/57=30 %	1/57=2 %
Low-side kV	18/57=32 %	21/57=37 %	16/57=28 %	2/57=4 %
Oil temperature	4/55=7 %	5/55=9 %	13/55=24 %	33/55=60 %
Winding hot-spot temperatures	4/55=7 %	4/55=7 %	10/55=18 %	37/55=67 %
Ambient temperature	1/54=2 %	1/54=2 %	17/54=31 %	35/54=65 %
Cooling-system status	4/55=7 %	8/55=15 %	8/55=15 %	35/55=64 %
Combustible gas density	2/55=4 %	4/55=7 %	7/55=13 %	42/55=76 %
Real-time operating limits determined by substation equipment/systems	7/57=12 %	3/57=5 %	1/57=2 %	46/57=81 %
Voltage regulation control status	10/56=18 %	9/56=16 %	9/56=16 %	28/56=50 %

Table 1.1-17 — Telemetry Data for Transmission Transformers (100-230 kV) within Respondents' Areas of Responsibility

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (<100 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Tap position	4/54=7 %	6/54=11 %	21/54=39 %	23/54=43 %
High-side MW and Mvars	6/56=11 %	12/56=21 %	27/56=48 %	11/56=20 %
High-side kV	10/56=18 %	15/56=27 %	21/56=38 %	10/56=18 %
Low-side MW and Mvars	7/56=13 %	13/56=23 %	24/56=43 %	12/56=21 %
Low-side kV	7/56=13 %	15/56=27 %	22/56=39 %	12/56=21 %
Oil temperature	2/54=4 %	2/54=4 %	11/54=20 %	39/54=72 %
Winding hot-spot temperatures	2/54=4 %	2/54=4 %	11/54=20 %	39/54=72 %
Ambient temperature	0/54=0 %	2/54=4 %	8/54=15 %	44/54=81 %
Cooling-system status	1/55=2 %	2/55=4 %	9/55=16 %	43/55=78 %
Combustible gas density	1/53=2 %	2/53=4 %	6/53=11 %	44/53=83 %
Real-time operating limits determined by substation equipment/systems	4/55=7 %	1/55=2 %	2/55=4 %	2/55=4 %
Voltage regulation control status	5/54=9 %	7/54=13 %	6/54=11 %	36/54=67 %

Table 1.1-18 — Telemetry Data for Transmission Transformers (less than 100 kV) within Respondents' Areas of Responsibility

Transmission Transformer Data for Adjacent Areas

The respondents were asked to quantify telemetry data they receive ("all," "most," "some," or "none") for transmission transformers (at various voltage levels) from areas adjacent to their areas of responsibility. Table 1.1-19, Table 1.1-20, and Table 1.1-21 summarize the responses. The majority of respondents do not receive telemetry data for transmission transformers in adjacent areas.

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (345-765 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Tap position	0/53=0 %	4/53=8 %	7/53=13 %	42/53=79 %
High-side MW and Mvars	5/53=9 %	5/53=9 %	24/53=45 %	19/53=36 %
High-side kV	4/53=8 %	6/53=11 %	25/53=47 %	18/53=34 %
Low-side MW and Mvars	4/53=8 %	3/53=6 %	27/53=51 %	19/53=36 %
Low-side kV	5/53=9 %	2/53=4 %	27/53=51 %	19/53=36 %
Oil temperature	0/51=0 %	0/51=0 %	2/51=4 %	49/51=96 %
Winding hot-spot temperatures	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Ambient temperature	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Cooling-system status	0/52=0 %	0/52=0 %	2/52=4 %	50/52=96 %
Combustible gas density	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Real-time operating limits determined by substation equipment/systems	1/53=2 %	0/53=0 %	1/53=2 %	51/53=96 %
Voltage regulation control status	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %

Table 1.1-19 — Telemetry Data for Transmission Transformers (345-765 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (100-230 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Tap position	1/54=2 %	1/54=2 %	7/54=13 %	45/54=83 %
High-side MW and Mvars	2/55=4 %	5/55=9 %	24/55=44 %	24/55=44 %
High-side kV	2/55=4 %	6/55=11 %	25/55=45 %	22/55=40 %
Low-side MW and Mvars	2/54=4 %	5/54=9 %	24/54=44 %	23/54=43 %
Low-side kV	2/55=4 %	4/55=7 %	23/55=42 %	26/55=47 %
Oil temperature	0/53=0 %	0/53=0 %	2/53=4 %	51/53=96 %
Winding hot-spot temperatures	0/53=0 %	0/53=0 %	1/53=2 %	52/53=98 %
Ambient temperature	0/53=0 %	0/53=0 %	1/53=2 %	52/53=98 %
Cooling-system status	0/53=0 %	1/53=2 %	1/53=2 %	51/53=96 %
Combustible gas density	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Real-time operating limits determined by substation equipment/systems	0/54=0 %	1/54=2 %	1/54=2 %	52/54=96 %
Voltage regulation control status	0/53=0 %	0/53=0 %	2/53=4 %	51/53=96 %

Table 1.1-20 — Telemetry Data for Transmission Transformers (100-230 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (<100 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Tap position	0/53=0 %	1/53=2 %	6/53=11 %	46/53=87 %
High-side MW and Mvars	0/54=0 %	4/54=7 %	15/54=28 %	35/54=65 %
High-side kV	0/54=0 %	5/54=9 %	14/54=26 %	35/54=65 %
Low-side MW and Mvars	0/54=0 %	5/54=9 %	14/54=26 %	35/54=65 %
Low-side kV	1/53=2 %	2/53=4 %	14/53=26 %	36/53=68 %
Oil temperature	0/52=0 %	0/52=0 %	2/52=4 %	50/52=96 %
Winding hot-spot temperatures	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Ambient temperature	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Cooling-system status	0/51=0 %	1/51=2 %	2/51=4 %	48/51=94 %
Combustible gas density	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Real-time operating limits determined by substation equipment/systems	0/53=0 %	1/53=2 %	0/53=0 %	52/53=98 %
Voltage regulation control status	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %

Table 1.1-21 — Telemetry Data for Transmission Transformers (100-230 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Substation Switching Device Telemetry Data

This subsection summarizes findings for substation switching device telemetry data. These data are gathered from substation circuit breakers and disconnect switches. All survey respondents have some form of substation switching device telemetry data available; 93 percent rate the availability of substation switching device data "essential" for enhancing their situational awareness.

Substation Switching Device Data within Respondents' Areas of Responsibility

Respondents were asked to quantify the telemetry data they receive ("all," "most," "some," or "none") for substation circuit breakers and disconnect switches (at various voltage levels) within their areas of responsibility. Table 1.1-22, Table 1.1-23, and Table 1.1-24 summarize the responses. Substation circuit breaker status data are the most commonly received.

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (345-765 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	41/51=80 %	4/51=8 %	0/51=0 %	6/51=12 %
Breaker disconnect switch status	11/51=22 %	9/51=18 %	14/51=27 %	17/51=33 %
Bus tie switch status	15/50=30 %	13/50=26 %	9/50=18 %	13/50=26 %
Bypass switch status	13/50=26 %	7/50=14 %	6/50=12 %	24/50=48 %
Transformer disconnect switch status	15/51=29 %	13/51=25 %	9/51=18 %	14/51=27 %
Line disconnect switch status	16/50=32 %	11/50=22 %	7/50=14 %	16/50=32 %
Reactor/Capacitor bank disconnect switch status	19/51=37 %	11/51=22 %	7/51=14 %	14/51=27 %

Table 1.1-22 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (345-765 kV) within Respondents' Areas of Responsibility

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (100-230 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	42/56=75 %	11/56=20 %	3/56=5 %	0/56=0 %
Breaker disconnect switch status	9/56=16 %	7/56=13 %	24/56=43 %	16/56=29 %
Bus tie switch status	14/55=25 %	14/55=25 %	14/55=25 %	13/55=24 %
Bypass switch status	9/55=16 %	9/55=16 %	11/55=20 %	26/55=47 %
Transformer disconnect switch status	10/54=19 %	15/54=28 %	15/54=28 %	15/54=28 %
Line disconnect switch status	9/55=16 %	13/55=24 %	20/55=36 %	13/55=24 %
Reactor/Capacitor bank disconnect switch status	16/56=29 %	15/56=27 %	13/56=23 %	12/56=21 %

Table 1.1-23 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (100-230 kV) within Respondents' Areas of Responsibility

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (< 100 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	42/56=75 %	11/56=20 %	3/56=5 %	0/56=0 %
Breaker disconnect switch status	9/56=16 %	7/56=13 %	24/56=43 %	16/56=29 %
Bus tie switch status	14/55=25 %	14/55=25 %	14/55=25 %	13/55=24 %
Bypass switch status	9/55=16 %	9/55=16 %	11/55=20 %	26/55=47 %
Transformer disconnect switch status	10/54=19 %	15/54=28 %	15/54=28 %	15/54=28 %
Line disconnect switch status	9/55=16 %	13/55=24 %	20/55=36 %	13/55=24 %
Reactor/Capacitor bank disconnect switch status	16/56=29 %	15/56=27 %	13/56=23 %	12/56=21 %

Table 1.1-24 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (< 100 kV) within Respondents' Areas of Responsibility

Substation Switching Device Data for Adjacent Areas

The survey asked respondents to quantify telemetry data they receive ("all," "most," "some," or "none") for substation circuit breakers and disconnect switches (at various voltage levels) from areas adjacent to their areas of responsibility. Table 1.1-25, Table 1.1-26, and Table 1.1-27 summarize the responses. The majority of respondents do not receive telemetry data for substation switching devices in adjacent areas.

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (345-765 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	7/53=13 %	7/53=13 %	27/53=51 %	12/53=23 %
Breaker disconnect switch status	1/52=2 %	4/52=8 %	13/52=25 %	34/52=65 %
Bus tie switch status	3/52=6 %	2/52=4 %	15/52=29 %	32/52=62 %
Bypass switch status	2/51=4 %	2/51=4 %	11/51=22 %	36/51=71 %
Transformer disconnect switch status	2/52=4 %	4/52=8 %	13/52=25 %	33/52=63 %
Line disconnect switch status	2/52=4 %	3/52=6 %	15/52=29 %	32/52=62 %
Reactor/Capacitor bank disconnect switch status	3/52=6 %	3/52=6 %	19/52=37 %	27/52=52 %

Table 1.1-25 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (345-765 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (100-230 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	5/54=9 %	4/54=7 %	38/54=70 %	7/54=13 %
Breaker disconnect switch status	0/53=0 %	1/53=2 %	13/53=25 %	39/53=74 %
Bus tie switch status	1/53=2 %	2/53=4 %	19/53=36 %	31/53=58 %
Bypass switch status	0/53=0 %	2/53=4 %	12/53=23 %	39/53=74 %
Transformer disconnect switch status	1/53=2 %	3/53=6 %	18/53=34 %	31/53=58 %
Line disconnect switch status	1/53=2 %	1/53=2 %	19/53=36 %	32/53=60 %
Reactor/Capacitor bank disconnect switch status	1/53=2 %	2/53=4 %	21/53=40 %	29/53=55 %

Table 1.1-26 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (100-230 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (< 100 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	2/52=4 %	2/52=4 %	21/52=40 %	27/52=52 %
Breaker disconnect switch status	0/51=0 %	0/51=0 %	6/51=12 %	45/51=88 %
Bus tie switch status	0/51=0 %	0/51=0 %	8/51=16 %	43/51=84 %
Bypass switch status	0/50=0 %	0/50=0 %	8/50=16 %	42/50=84 %
Transformer disconnect switch status	1/51=2 %	0/51=0 %	11/51=22 %	39/51=76 %
Line disconnect switch status	1/51=2 %	0/51=0 %	10/51=20 %	40/51=78 %
Reactor/Capacitor bank disconnect switch status	1/51=2 %	0/51=0 %	11/51=22 %	39/51=76 %

Table 1.1-27 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (< 100 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Telemetry Data Maintenance and Support Practices

The Real-Time Tools Survey includes questions pertaining to routine, regular activities that ensure the quality and integrity of telemetered data. A majority of respondents (66 percent) perform maintenance activities related to the availability of their telemetry data. Respondents that have some form of maintenance activity consider it to be "essential" (56 percent) or "desirable" (42 percent) for situational awareness. A majority (78 percent) of respondents that perform maintenance have processes or procedures for telemetry personnel to perform regular, manual checks of the data. A majority (78 percent) of the respondents perform maintenance activities "as needed."

Fifty percent or more of respondents who use testing/debugging/diagnostic tools to check telemetry data employ the following tools:

- Remote terminal unit (RTU) test set (RTU simulator)
- Data communication network analyzer
- EMS host communication traffic viewer/analyzer
- Communication error reporting on EMS
- Quality code processing
- On-line diagnostics (running in real time)

The survey includes questions about tools/processes to make support personnel aware when telemetered data are erroneous or not available. A majority of respondents (94 percent) notify the personnel responsible for the telemetered data if the data are erroneous or are not received. A majority (78 percent) consider these notifications "essential" for situational awareness. The most common notification method is an alarm; the operator receiving the alarm calls support personnel to address the problem. Respondents also have provisions for personnel to remotely support operators when telemetry data issues arise.

Recommendations for New Reliability Standards

Telemetry data are essential for operators to monitor the status of bulk electric system elements and parameters. Telemetry data are typically the main input to other applications/tools (i.e., SCADA applications, alarm tools, state estimator) used to monitor bulk electric system elements and parameters. The following discussions support RTBPTF's major recommendation to make telemetry data systems mandatory (see the Reliability Toolbox Recommendation and Rationale section, which describes the recommended mandatory tools, including telemetry data systems, for RCs and TOPs).

RTBPTF also recognizes that entities cannot be expected to use specific tools to monitor the bulk electric system without stipulating which components of the system are to be monitored or require telemetry data, so the following subsections discuss this issue. Where appropriate, RTBPTF recommends modifications to existing standards.

Recommendation – S1

Mandate the following reliability tools as mandatory monitoring and analysis tools

- Alarm Tools
- Telemetry Data Systems
- Network Topology Processor
- State Estimator
- Contingency Analysis

Telemetry data systems: mandatory monitoring and analysis tool

Telemetry data systems update status and analog values from conventional SCADA/EMSs and from the SCADA/EMSs of others (via ICCP, ISN, etc.) continuously in real or near-real time. Telemetry data systems are the primary sources of information that directly and indirectly (by supporting other applications) provide situational awareness to operators. RTBPTF believes that telemetry data systems are essential for operators to monitor and maintain the reliability of the bulk electric system. Existing NERC reliability standards implicitly assume the use of telemetry data systems to aid RCs and TOPs in maintaining situational awareness for the bulk electric system. Specifying telemetry data systems as part of the Reliability Toolbox[4] eliminates the vagueness in the current NERC reliability standards and clarifies that telemetry data systems, as defined, are mandatory.

Telemetry data system availability

Because RTBPTF recommends that telemetry data systems be mandatory tools for maintaining bulk electric system situational awareness, these tools must be highly redundant and available. Thus, RTBPTF also recommends requiring that operators be aware of the availability status of these tools. RTBPTF recommendation presented in Section 5.4, Critical Applications Monitoring, addresses telemetry data system availability. RTBPTF believes that the recommendations in Section 5.4 are sufficient to maintain operators' situational awareness of the availability of this critical monitoring tool.

"Bulk Electric System" definition

The term "bulk electric system" appears throughout numerous existing NERC reliability standards. The NERC Glossary defines "bulk electric system" as follows: "[a]s defined by the Regional Reliability Organization, the electrical generation of resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages 100 kV or higher. Radial transmission facilities serving only load with one transmission

[4] See the Reliability Toolbox Recommendation and Rationale section.

source are generally not included in this definition." However, section 215(a)(1) of the Federal Powers Act defines the bulk power system as "[f]acilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy."

The *FERC Staff Assessment*[5] notes that "[t]he FPA and NERC definitions obviously differ. The standards currently are applied only to the Bulk Electric System as defined by each Region. However, section 215(a)(3) of the FPA defines Reliability Standard as a requirement approved by the Commission to provide for reliable operation of the Bulk-Power System. The term Bulk Electric System does not appear to include all the system components from all non-distribution voltage levels, control systems, and electric energy from all generating facilities needed to maintain transmission system reliability included in the definition of Bulk-Power System."

The *FERC Staff Assessment* states, "[e]lements of numerous standards appear to be subject to multiple interpretations, especially with regard to the specificity of the standards' requirements, measurability, and degrees of compliance. This ambiguity also extends to the differing definitions for the Bulk-Power System and the Bulk Electric System." The *FERC Staff Assessment* further notes, "[w]hen the task of defining the Bulk Electric System is delegated to each RRO, the result could be conflicting multiple definitions that subject different facilities to, or exclude different facilities from, the requirements of the standards."

Recommendation – I1

Define what constitutes bulk electric system elements and parameters as they relate to existing standards.

RTBPTF Recommendation

RTBPTF recommends that NERC define what constitutes bulk electric system elements and parameters as they relate to existing standards. Specifically, NERC needs to resolve whether the bulk electric system should continue to be defined by regional reliability organizations (RROs) or whether a single NERC definition should be adopted. In either case, the defined criteria shall be applied to all of the NERC reliability standards. The criteria for classifying bulk electric system elements and parameters need to be clearly and unambiguously stated

[5] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

so that reliability entities can comply fully with reliability standards that refer to the bulk electric system.

Rationale

The bulk electric system definition is particularly important for numerous existing NERC standards that specify and require “monitoring” by reliability entities of specific data and bulk electric system elements and parameters. The standards have common, well-established requirements but, in most cases, are not specific about how reliability entities are to measure and/or comply with the monitoring requirements.

The survey results quantified the number of telemetry data currently available for elements at different voltage levels (100 kV and above). Not all telemetry data for these elements are currently available. This is an interesting finding because the 100-kV level is explicitly identified in the current definition of the bulk electric system. The survey results illustrate that respondents’ telemetry data practices are not uniform. The results also suggest that design standards (related to telemetry measurements for transmission facilities) are typically developed by transmission operators for their own use. These practices and standards do not appear to be completely supportive of NERC-mandated requirements for monitoring of the bulk electric system elements by reliability entities.

Monitoring standards/requirements

The existing NERC standards listed below require that reliability entities monitor bulk electric system elements and parameters. In RTBPTF’s opinion, the word “monitor” does not imply viewing large amounts of raw telemetered data but rather viewing data in a manner and format that allows operators to rapidly judge the state of the bulk electric system and take corrective action when necessary. Reliability entities could monitor bulk electric system elements and parameters directly using tools such as state estimators (with defined measurement-observability requirements) or other indirect approaches such as calculated points based on existing telemetry data (i.e., calculated MVA based on MW and Mvar telemetered data). However, all such monitoring approaches depend on information obtained from processing raw data. Processing is necessary to use telemetry data for monitoring; this understanding forms the context for the discussions of monitoring standards below.

Where noted below, RTBPTF recommends additions/modifications to standards and their corresponding requirements and/or measures. The discussion emphasizes use of available tools to aid reliability entities in monitoring bulk electric system elements and parameters. The recommendations below assume that the definition of the term “bulk electric system” is clarified per the RTBPTF recommendation above.

1. NERC Reliability Standard TOP-005, Operational Reliability Information

The purpose of TOP-005 is “[t]o ensure reliability entities have the operating data needed to monitor system conditions within their areas.” This standard specifies what data are needed by reliability entities to monitor the bulk power system. Requirement R1 states, “[e]ach Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area… [e]ach Reliability Coordinator shall identify the data requirements from the list [specified] in [the]…‘Electric System Reliability Data’ and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.”

RTBPTF Recommendations

The use of telemetry data systems is ubiquitous in the industry. Moreover, improvements in data communication technologies have dramatically increased the update frequency that is now common to all systems. The “Electric System Reliability Data” appendix[6] specifies the data required from each RC’s TOPs and BAs to perform operational reliability assessments and to coordinate reliable operations within the RC’s area. The “Electric System Reliability Data” appendix also lists the types of data that RCs, TOPs, and BAs are expected to provide to and share with each other.

In general, RTBPTF believes that the update frequency for certain types of reliability data specified in the “Electric System Reliability Data” appendix of at least every 10 minutes is not sufficient to monitor critical reliability parameters in real time. RTBPTF recommends changing the update frequency requirement to every 10 seconds. RTBPTF believes that most commercially available telemetry data systems used industry-wide are capable of supporting a 10-second update frequency.

The specific recommendations for modifications to the items listed in the “Electric System Reliability Data” appendix are explained in Table 1.1-28 (see “Discussion” column).

Rationale

Table 1.1-28 lists the contents of the “Electric System Reliability Data” appendix; the “Discussion” column contains RTBPTF’s recommendations for modifications to items listed in the appendix together with the corresponding rationale.

[6] This is an appendix to Standard TOP-005.

Type of Reliability Data	Discussion
1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint: 1.1.1 Status 1.1.2 MW or ampere loadings 1.1.3 MVA capability 1.1.4 Transformer tap and phase angle settings 1.1.5 Key voltages	Recommendations: 1. RTBPTF recommends revising item 1.1.2 "MW or ampere loadings" to read: "MW, Mvar, and ampere loadings." 2. RTBPTF recommends that the following transmission data specified in item 1.1 of the "Electric System Reliability Data" appendix (with the exception of MVA capability data) shall be provided and updated at least every 10 seconds: • Status • MW or ampere loadings • Transformer tap and phase angle settings • Key voltages 3. RTBPTF recommends that MVA capability data shall be "provided upon every update" or "as soon as available." Rationale: 1. For completeness, the "Mvar loadings" for transmission data should be part of item 1.1.2 of the "Electric Systems Reliability Data" appendix. Mvar data are essential to ascertain proper loadings of transmission equipment. 2. RTBPTF believes that an update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current data to monitor critical reliability parameters in real time. Transmission data may be needed by other applications such as the state estimator and/or contingency analysis to detect actual or potential SOL/IROL violations. More frequent updates of transmission data are needed to provide better analysis for operators. 3. RTBPTF believes that the MVA capability data (and the corresponding update frequency for the data) are addressed by Standard TOP-002, Requirement 11, which states, "[t]he Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs… The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator." It is not necessary to provide the MVA capability information unless new updates are available.

Type of Reliability Data	Discussion
1.2. Generator data 1.2.1 Status 1.2.2 MW and Mvar capability 1.2.3 MW and Mvar net output 1.2.4 Status of automatic voltage control facilities	Recommendations: 1. RTBPTF recommends that the following generator data specified in item 1.2 of the “Electric System Reliability Data” appendix (with the exception of MW and Mvar capability data) shall be provided and updated at least every 10 seconds: • Status • MW and Mvar net output • Status of automatic voltage control facilities 2. RTBPTF recommends that MW and Mvar capability data shall be “provided upon every update” or “as soon as available.” Rationale: 1. RTBPTF believes that update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current data to monitor critical reliability parameters in real time. Generator data may be needed by other applications such as the state estimator and/or contingency analysis to detect actual or potential SOL/IROL violations. More frequent update of generator data is needed to provide better analysis for operators. 2. The generator MW and Mvar capability data (and the corresponding update frequency for the data) are addressed by Standard TOP-002, Requirement 11, which states, “[t]he Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs… The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions [i.e., generator capability]; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.” It is not necessary to provide the generator MW and Mvar capability information unless new updates are available.
1.3. Operating reserve 1.3.1 MW reserve available within ten minutes	Recommendation: 1. RTBPTF recommends that the generator data specified in item 1.3 of the “Electric System Reliability Data” appendix shall be provided at least every 10 seconds. Rationale: 1. RTBPTF believes that update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current data to monitor critical reliability parameters (i.e., operating reserves) in real time.

Type of Reliability Data	Discussion
1.4. Balancing Authority demand 1.4.1 Instantaneous	Recommendation: 1. RTBPTF recommends that the balancing authority demand data specified in item 1.4 of the "Electric System Reliability Data" appendix shall be provided at least every 10 seconds. Rationale: 1. RTBPTF believes that update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current operating data to monitor critical reliability parameters (i.e., instantaneous BA demand) in real time.
1.5. Interchange 1.5.1 Instantaneous actual interchange with each Balancing Authority 1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities 1.5.3 Interchange Schedules for the next 24 hours	Recommendations: 1. RTBPTF recommends that the interchange data specified in item 1.5 (with the exception of interchange schedules for the next 24 hours) of the "Electric System Reliability Data" appendix shall be provided at least every 10 seconds. 2. The interchange schedules for the next 24 hours shall be provided with every schedule update. Rationale: 1. RTBPTF believes that update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current operating data to monitor critical reliability parameters (i.e., instantaneous actual interchange with each BA and Current Interchange Schedules with each BA by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities) in real time. 2. RTBPTF believes that it is sufficient to provide interchange schedules for the next 24 hours when new updates are available, i.e., when schedules are changed.
1.6. Area Control Error and frequency 1.6.1 Instantaneous area control error 1.6.2 Clock hour area control error 1.6.3 System frequency at one or more locations in the Balancing Authority	Recommendations: 1. RTBPTF recommends that the area control error (ACE) and frequency data specified in item 1.6 (with the exception of clock-hour ACE) of the "Electric System Reliability Data" appendix shall be provided at least every 10 seconds. 2. RTBPTF recommends that the clock-hour ACE shall be provided with every hourly update. Rationale: 1. RTBPTF believes that update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current operating data to monitor critical reliability parameters (ACE and frequency data) in real time. 2. The clock-hour area control error does not need to be updated every 10 seconds; an hourly update of the data is sufficient.

Type of Reliability Data	Discussion
2. Other operating information updated as soon as available 2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect 2.2. Forecast of operating reserve at peak, and time of peak for current day and next day 2.3. Forecast peak demand for current day and next day 2.4. Forecast changes in equipment status 2.5. New facilities in place. 2.6. New or degraded special protection systems 2.7. Emergency operating procedures in effect 2.8. Severe weather, fire, or earthquake 2.9. Multi-site sabotage	Recommendation: 1. RTBPTF recommends that an additional item (i.e., Status of Special Protection Systems) be added to item 2 in this list. Rationale: 1. Standard IRO-005 (Requirement R1) states "[e]ach Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following…R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading." For completeness, the status of Special Protection Schemes should be included in this list.

Table 1.1-28 — Electric System Reliability Data (TOP-005, Requirement R1, Attachment 1) and RTBPTF Recommendations

3. NERC Reliability Standard IRO-002, Reliability Coordination – Facilities

RCs need information, tools, and other capabilities to perform their responsibilities. Requirement R5 of IRO-002 states "[e]ach Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure."

Requirement R6 states "[e]ach Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area."

In context, the standards quoted above do not specify which bulk electric system elements need to be telemetered. Entities cannot be expected to use "information, tools, and other capabilities" without a clear understanding of the components of the system that need to be monitored or require telemetry data.

Recommendation – S2

Compile and maintain a list of all bulk electric system elements within RC's area of responsibility.

RTBPTF Recommendations

Once the bulk electric system definition is clarified, per the recommendation above, RTBPTF recommends that a new requirement be established under the current Standard IRO-002 (Reliability Coordination — Facilities) that shall apply to RCs and specify which bulk electric system elements need to be telemetered. The following requirement is recommended.[7]

PR1. Each reliability coordinator shall develop and maintain a list (the "Bulk Electric System Elements List") of specific bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) within its reliability coordinator area. The regional reliability organizations shall oversee this process within their regions. For consistency, this list shall be based upon the "Electric System Reliability Data" specified in Standard TOP-005. The Bulk Electric System Elements List shall contain the bulk electric system elements (within the reliability coordinator's area) necessary to allow identification of potential or actual SOL/IROL violations.

PR1.1. Each reliability coordinator shall specify the monitoring methodology for each item on its Bulk Electric System Elements List (i.e., whether monitoring by direct or indirect methods).

PR1.2. For bulk electric system elements to be monitored directly, each reliability coordinator shall also specify the characteristics for specific data types (i.e., MW, kV, breaker status, etc.) that shall be telemetered for specific facilities (i.e., transmission lines, transformers, generators, etc.) at specific voltage levels (i.e., 765 kV, 500 kV, etc.). The telemetry data characteristics shall include, but not be limited to, the following characteristics: update frequency (whether periodic or by exception), latency characteristics, and quality codes.

PR1.3. Each reliability coordinator shall telemeter items listed in the Bulk Electric System Elements List (generators, transmission lines, buses, transformers, breakers, etc.) for which a direct monitoring methodology is specified and shall provide information that can be easily

[7] Proposed requirements are designated "PR," and proposed measures are designated "PM."

understood and interpreted by the reliability coordinator's operations personnel. Update frequency shall conform to the "Electric System Reliability Data" list as specified[8] in Standard TOP-005 for each data type.

RTBPTF recommends the following measure for the requirement stated above:

PM1. The reliability coordinator shall maintain the "Bulk Electric System Elements List" document as stated in Requirement PR1.

Rationale

RTBPTF believes that a requirement specifying a methodology for documenting the bulk electric system elements for which telemetering is required within an RC area removes any vagueness regarding what data must be provided (and by what methodology and update frequency) by reliability entities within the RC area. The recommendation above formalizes a process for RCs to document which bulk electric system elements they need to monitor and telemeter within their RC area.

4. *NERC Reliability Standard IRO-005, Reliability Coordination — Current-Day Operations*

Standard IRO-005 states that "[t]he Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas."

Requirement R1 states "each reliability coordinator shall monitor its reliability coordinator area parameters, including but not limited to:[9]

R1.1. Current status of bulk electric system elements (transmission or generation including critical auxiliaries such as automatic voltage regulators and special protection systems) and system loading;
R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, and including the plan's viability and scope;
R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, and including the plan's viability and scope;
R1.4. System real and reactive reserves (actual versus required);
R1.5. Capacity and energy adequacy conditions;
R1.6. Current ACE for all of its balancing authorities;

[8] Take note that the RTBPTF recommends changes to the "Electric System Reliability Data".
[9] The numbering scheme for these requirements were adapted to the current numbering scheme in the current version of Standard IRO-005.

R1.7. Current local or transmission loading relief procedures in effect;
R1.8. Planned generation dispatches;
R1.9. Planned transmission or generation outages; and
R1.10. Contingency events

For each of the requirements stated above for Standard IRO-005 (Requirement R1), no measures are currently specified. Requirement R1 mandates that each RC monitor its RC area parameters. Although the requirement is specific as to the parameters that need to be monitored, it does not specify any compliance measures.

Recommendation – S3

Add new requirements and measures pertaining to RC monitoring of the bulk electric system.

RTBPTF Recommendations

In general, the survey results support the availability of telemetry data for the RC area parameters mentioned in Standard IRO-005 (Requirement R1). As discussed previously, it is difficult to recommend measures for Standard IRO-005 (Requirement R1) without resolving the definition of the term "bulk electric system." Once the bulk electric system definition is clarified, RTBPTF recommends the following measures[10] for Standard IRO-005 (Requirements R1)[11].

PM1. The following are measures for each of the requirements R1.1-R1.6, and R1.10:
PM1.1. The reliability coordinator's Bulk Electric System List (as required in Standard IRO-002)[12] shall contain the status of bulk electric system elements (transmission or generation including critical auxiliaries such as automatic voltage regulators and special protection systems) and system loading necessary for the reliability coordinator to monitor its reliability coordinator area parameters. The reliability coordinator shall demonstrate, on request, that the reliability coordinator is monitoring every item listed in the Bulk Electric System Elements List.
In addition to the reliability coordinator's Bulk Electric System List, the reliability coordinator shall also

[10] The numbering scheme for these proposed measures (PM) coincides with the existing requirements – i.e., the proposed measure for Requirement R1.1 is numbered PM1.1.
[11] RTBPTF omitted any recommendations for measures related to Standard IRO-005 (Requirements R1.7-R.9) because they are not within RTBPTF's scope; these reliability coordinator parameters do not involve telemetry data or other tools discussed in this report.
[12] See recommendations for Standard IRO-002 above.

demonstrate the monitoring of bulk electric system elements (transmission or generation including critical auxiliaries such as automatic voltage regulators and special protection systems) and system loading necessary for the reliability coordinator to monitor its reliability coordinator area parameters within its wide area.

PM1.2. The reliability coordinator shall demonstrate the monitoring of current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, and including the plan's viability and scope by having a display showing the contingency analysis base-case solution available to the reliability coordinator. The display shall show current pre-contingency element conditions within the reliability coordinator's wide area.

PM1.3. The reliability coordinator shall demonstrate the monitoring of current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, and including the plan's viability and scope by having a display showing the contingency analysis solution for each defined contingency available to the reliability coordinator. The display shall show current post-contingency element conditions within the reliability coordinator's wide area.

PM1.4. The reliability coordinator shall demonstrate the monitoring of system real and reactive reserves (actual versus required) by having displays (or visualization tools) showing the real-time information related to system real and reactive reserves[13] (actual versus required) available to the reliability coordinator. The displays (or visualization tools) shall show information on system real and reactive reserves (actual versus required) within the reliability coordinator's wide area.

PM1.5. The reliability coordinator shall demonstrate the monitoring of capacity and energy adequacy conditions by having displays (or visualization tools) showing the real-time information related to capacity and energy adequacy conditions available to the reliability coordinator. The displays (or visualization tools) shall show information on capacity and energy adequacy conditions within the reliability coordinator's wide area.

[13] Note that one of the major issues that RTBPTF identifies in this report (see the Introduction) as needing resolution from NERC and the industry is the specification of what constitutes acceptable reactive reserves.

PM1.6. The reliability coordinator shall demonstrate the monitoring of the current ACE for all of its balancing authorities by having displays (or visualization tools) showing the real-time ACE for all of its balancing authorities available to the reliability coordinator.

PM1.7. The reliability coordinator shall demonstrate the monitoring contingency events by having displays (or visualization tools) showing time-stamped contingency events available to the reliability coordinator. The displays (or visualization tools) shall show contingency events data/information within the reliability coordinator's wide area.

Rationale

For the proposed measure PM1.1, RTBPTF interprets the "current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading" as stated in Standard IRO-005 (Requirement R1.1) as referring to some of the items contained in the Bulk Electric System Elements List; RTBPTF recommends the Bulk Electric System Elements List above as a new requirement in Standard IRO-002. Relating the measure for Standard IRO-005 (Requirement R1.1) to the Bulk Electric System Elements List provides a direct way to document what is being monitored by reliability coordinators.

For the proposed measures PM1.2 and PM1.3, RTBPTF believes that having the contingency analysis base-case solution and contingency analysis solution for each defined contingency available to the RC sufficiently demonstrates the monitoring of "current pre- and post-contingency element conditions." Telemetry data indirectly support the contingency analysis application output/solution. Section 2.6 of this report, Contingency Analysis, discusses recommendations for contingency analysis.

For proposed measure PM1.4, RTBPTF interprets "system real and reactive reserves (actual versus required)" as the output of the reactive reserve monitor (a type of visualization tool). This application monitors reactive reserves (static and dynamic) in local geographic areas or major load centers and can send an alarm to the operator when a unit in the area reaches its reactive capability or the minimum reactive reserve requirement for the area is approached. Telemetry data indirectly support the reactive reserve monitor output/solution. Section 2.2 of this report, Visualization Techniques, discusses recommendations for visualization tools.

For proposed measure PM1.5, RTBPTF interprets “capacity and energy adequacy conditions” as the output of the capacity assessment application.[14] The capacity assessment application gives an overview of available generation capacity (MW or Mvar) in real time. Telemetry data indirectly support the capacity assessment application output/solution. Section 2.12 of this report, Capacity Assessment, discusses recommendations for the capacity assessment application.

For proposed measure PM1.6, RTBPTF believes that the current ACE for all of an RC’s BAs could be obtained as ICCP-specific data from the BAs. Each RC could demonstrate compliance by showing the monitoring (through ICCP data exchange or direct telemetry methods) of the current ACE for all the RC’s BAs. A summary display showing the ACE for all of an RC’s BAs provides a measure for Standard IRO-005 (Requirement R1.6). Standard TOP-005 also requires current ACE data.

For proposed measure PM1.10, RTBPTF believes that a contingency event could result from the change in status of a single or a combination of multiple bulk electric system elements. For example, when a 230-kV transmission line contingency event occurs, it could be the result of all of the transmission circuit breakers related to the 230-kV transmission line having a change of status to “open.” A summary display showing the contingency events provides a measure for Standard IRO-005 (Requirement R1.10). This summary display could also be the output of the alarm tool that selectively lists all of the contingency events for the RC wide area.

5. NERC Reliability Standard PRC-001, System Protection Coordination
The purpose of Standard PRC-001 is “to ensure system protection is coordinated among operating entities.” Requirement R6 mandates that “[e]ach 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.”

Standard PRC-001 (Requirement R6) is the same as Standard IRO-005 (Requirement 1.1) as related to special protection schemes. Standard PRC-001 applies to TOPs and BAs; Standard IRO-005 applies to RCs.

There are currently no specified measures for Standard PRC-001 (Requirement R6).

[14] An equivalent application could be substituted for a capacity assessment application as long as the data and displays (or visualization tools) show the “capacity and energy adequacy conditions.”

RTBPTF Recommendation

In PRC-001 (Requirement R6), RTBPTF interprets “monitor” to mean that special protection system (SPS) status needs to be provided via telemetry or another real-time method. Telemetry is the most direct and current method for monitoring special monitoring systems. RTBPTF recommends that PRC-001 (Requirement R6) be modified to the following:

PR1. Each transmission operator and balancing authority shall monitor the status of each special protection system (SPS) in the transmission operator’s or balancing authority’s area via telemetry or another real-time method, and shall notify affected transmission operators and balancing authorities of each change in status. Each transmission operator and balancing authority shall also notify the host reliability coordinator via the use of telemetry data systems of each change in status.

RTBPTF recommends the following measure for the requirement stated above:

PM1. Each transmission operator and balancing authority shall demonstrate the monitoring the status of each special protection system (SPS) in the transmission operator’s or balancing authority’s area by having displays (or visualization tools) showing the real-time information related to the status of each special protection system (SPS) in the transmission operator’s or balancing authority’s area.

Rationale

RTBPTF interprets the monitoring of “the status of each Special Protection System” as the output of the remedial action scheme (RAS) tool (a subset of visualization tools discussed in Section 2.2, Visualization Techniques). The RAS allows users to: monitor the status of critical power system parameters, measure the proximity of these parameters to the triggering conditions for special protection schemes or total system failure, and alarm operators and advise them of actions required to mitigate pending problems. Telemetry data indirectly support the RAS application output/solution. Section 2.2, Visualization Techniques, of this report discusses the recommendations for visualization tools (including RAS). In addition, RTBPTF has recommended adding monitoring of the status of SPSs as part of the ‘Electric System Reliability Data’ appendix (see recommendations for Standard TOP-005).

6. NERC Reliability Standard TOP-006, Monitoring System Conditions

The purpose of Standard TOP-006 is “to ensure critical reliability parameters are monitored in real-time.” Standard TOP-006 specifies the critical system parameters to be monitored by responsible entities. The requirements for Standard TOP-006[15] are listed below:

R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.

R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.

R4. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.

The *FERC Staff Assessment* states: "[t]he standard does not have any Compliance Measures and Levels of Noncompliance and without such specificity, the ERO will not have norms that are specific enough to implement consistent and effective enforcement." On the topic of real-time monitoring in Standard TOP-006,[16] The *FERC Staff Assessment* states: "while the requirements identify the data to be gathered, they fail to describe the tools necessary to turn that data into critical reliability parameters, i.e., system capability or contingency analysis, which are required to achieve situational awareness. Reliability Coordinators, Transmission Operators, and Balancing

[15] These requirements are listed verbatim from Standard TOP-006.
[16] "To ensure critical reliability parameters are monitored in real-time."

Authorities must be aware of the status of their respective systems, and such situational awareness cannot be obtained by viewing massive amounts of raw data. The standard does not contain any Measures to assess compliance with Requirements or Levels of Non-Compliance required for enforcement."

RTBPTF Recommendation

RTBPTF interprets "critical reliability parameters" as outputs of some of the tools/applications described throughout this report and through the use of the displays (or visualization tools) for each respective tool/application. The tools/applications described throughout this report turn raw data (most of which are telemetry data) into "critical reliability parameters." RTBPTF recommends measures for the existing requirements within Standard TOP-006 that applicable entities demonstrate actual usage of such tools/applications pertinent to each requirement. RTBPTF recommends the following measures[17] for Standard TOP-006.

- PM1. Each transmission operator and balancing authority shall demonstrate the knowledge of the status of all generation resources available for use by having displays (or visualization tools) showing the following:
  - PM1.1. A summary display showing the host balancing authority information of all generation resources available for use, obtained from the balancing authority area generator operators. This summary display shall be the output of the host balancing authority's capacity assessment (or equivalent) application.
  - PM1.2. The data from the summary display as stated in PM1.1 shall be shared with affected transmission operators and the reliability coordinator.
- PM2. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate the capability of monitoring of applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources by having displays (or visualization tools) showing the output of the reliability entity's telemetry data systems.
- PM3. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate the capability of providing appropriate technical information concerning protective relays to their operating personnel by having these documents (through paper copies or electronic documentation) readily available for their operating personnel.
- PM4. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate having the capability of obtaining

[17] The numbering scheme for these proposed measures (PM) coincides with the existing requirements (i.e., the proposed measure for Requirement R1 in numbered PM1).

information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern by having displays (or visualization tools) showing the output of the reliability entity's historical/real-time/forecast weather systems as well the output of the reliability entity's near-term load forecast systems.

PM5. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate the use of monitoring equipment (such as telemetry data systems and/or alarm tools) to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

PM6. Each balancing authority and transmission operator shall demonstrate the use of sufficient metering with suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations by requiring the reliability entity to demonstrate the usage of telemetry data systems and/or alarm tools sufficient to support the update frequency specified by Standard TOP-005, "Electric System Reliability Data" appendix.

PM7. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate the capability monitoring of system frequency by having displays (or visualization tools) showing real-time and current system frequency information.

Rationale

In general, the discussions below work in conjunction with RTBPTF's above recommendations for Standard IRO-002 and recommendations for modifications to the update frequency as mandated by Standard TOP-005. For each "critical reliability parameter," a specific tool(s)/application(s) is(are) suggested as a method to measure the usage of monitoring "critical reliability parameters."

For proposed measure PM1, RTBPTF believes that Requirement R1 works in conjunction with RTBPTF's recommendations for Standard IRO-002 and recommendations for modifications to the update frequency as mandated by Standard TOP-005 for "generation and transmission resources available for use." RTBPTF interprets this requirement as the active monitoring of bulk electric system elements (i.e., status of all generation and transmission resources available for use) within the entity's area of responsibility. In addition to monitoring of the status of all generation and transmission resources available for use, the critical reliability parameters specified in Requirement R1 could be derived using a capacity assessment (or equivalent) application. The capacity assessment (or equivalent) application gives an overview of available generation capacity (MW or Mvar) in real time. Telemetry data indirectly support the capacity assessment application output/solution. Section 2.12 of this report, Capacity Assessment, discusses the recommendations for the capacity assessment application.

For proposed measure PM2, RTBPTF believes that Requirement R2 works in conjunction with RTBPTF's recommendations above for modifications to update frequency as mandated by Standard TOP-005. RTBPTF interprets this requirement as the active monitoring of bulk electric system elements (i.e., applicable transmission-line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources) within the entity's area of responsibility by using the entity's telemetry data systems.

For proposed measure PM3, RTBPTF supports the notion of operators having access to documentation of appropriate technical information concerning protective relays.

For proposed measure PM4, RTBPTF believes that operators need historical/real-time/forecast weather information. These types of information are readily available from the Internet. The measure for this requirement mandates that weather information that may affect the real-time and forecasted load needs to be accessible to operators and used by the entity's near-term load forecast systems.

For proposed measure PM5, RTBPTF reiterates the need for demonstrated usage of monitoring equipment (such as telemetry data systems and/or alarm tools) to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

For proposed measure PM6, RTBPTF interprets "timely monitoring" as following the update frequency mandated by Standard TOP-005, "Electric System Reliability Data" appendix. An entity may choose to exceed the minimum requirement mandated by the appendix to ensure timely dissemination of critical information for operating personnel.

For proposed measure PM7, RTBPTF believes that reliability entities should demonstrate compliance by having displays (or visualization tools) that show real-time frequency from all telemetry sources.

7. NERC Reliability Standard VAR-001, Voltage and Reactive Control
The purpose of Standard VAR-001 is "to ensure voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in ***real time*** [emphasis added] to protect equipment and the reliable operation of the Interconnection." Requirement R1 mandates that "each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual

areas and with the areas of neighboring Transmission Operators." Standard VAR-001 (Requirement R1) does not specify any measures for compliance.

RTBPTF Recommendation

RTBPTF recommends that a measure be established for Standard VAR-001 (Requirement R1) that requires the documentation of formal policies and procedures to ensure voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the interconnection. The following measure is recommended for Standard VAR-001 (Requirement R1):

PM1. Each transmission operator shall document formal policies and procedures to ensure voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the interconnection. These formal policies and procedures shall include the list of bulk electric system elements that need to be monitored via telemetry, such as voltage telemetry levels (from generators, transmission substations, etc.), reactive flows (from generators, transmission substations, transmission lines, etc.), and reactive power resources (static and dynamic). This document shall be made readily available to operators and updated as necessary.

Rationale

The Real-Time Tools Survey results described in the Summary of Findings section above show that ***not*** all voltage levels, reactive flows, and reactive resources are available as telemetry data. Standard VAR-001 mandates "real-time" monitoring of these data. As stated previously, RTBPTF believes that "monitoring" does not imply viewing large amounts of raw telemetered data but rather viewing data in a manner and format that allows operators to rapidly judge the state of the bulk electric system and take corrective action if necessary. Transmission operators could use a state estimator (with defined measurement-observability requirements) to monitor voltage levels, reactive flows, and reactive resources in real time. To protect equipment and maintain reliable operation of the interconnection, the pre- and post-contingency analysis solution could also be used to monitor voltage levels, reactive flows, and reactive resources in real time and assess impacts of contingencies on the reliability of the interconnection.

8. NERC Reliability Standard COM-001, Telecommunications

Each RC, TOP, and BA needs adequate and reliable telecommunications facilities internally and to others for the exchange of the interconnection and operating information necessary to maintain reliability. Requirement R2 states "each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test, and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications."

RTBPTF Recommendation

Knowledge of the status of vital telecommunications facilities and equipment via telemetry internally and to/from related entities is essential for situational awareness. The telemetry data required to fulfill this requirement are closely tied to the issues addressed in Section 5.3, Facilities Monitoring, of this report. Section 1.2, ICCP-Specific Data, of this report addresses the methodology and management issues related to ICCP-specific data exchange. RTBPTF recommends rewording Requirement R2 as follows:

> R2. Each reliability coordinator, transmission operator, and balancing authority shall manage, alarm, test, and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications. At a minimum, reliability coordinators, transmission operators, and balancing authorities shall provide telemetry data by vital telecommunications equipment (1) internally, (2) between the reliability coordinator and its transmission operators and balancing authorities, and (3) with other reliability coordinators, transmission operators, and balancing authorities.

Rationale

RTBPTF believes that the new language recommended for Requirement R2 specifies the types of telemetry data systems (telecommunications facilities) that are required (i.e., to support internal communications within the entity's area of responsibility, communications between the reliability coordinator and its transmission operators and balancing authorities, and communications with other reliability coordinators, transmission operators, and balancing authorities.)

Recommendations for New Operating Guidelines

RTBPTF does not recommend development of new operating guidelines for telemetry data at this time. The recommendations listed within this section indicate the need to clarify measurement methods specified in existing standards and compliance procedures. These clarifications are necessary before establishing new operating guidelines for telemetry data.

Areas Requiring More Analysis

RTBPTF is not recommending additional areas for analysis related to Telemetry Data.

Examples of Excellence

RTBPTF cites the Northeast Power Coordinating Council's "Criteria for Classification of Bulk Power System Elements (A-10)[18]" document as an example of excellence in establishing and facilitating a process/methodology for classifying bulk power system elements (See EOE-1 in Appendix E).

[18] http://www.npcc.org/documents/regStandards/Criteria.aspx

Section 1.2
ICCP-Specific Data

Definition

The Inter-Control Center Communications Protocol (ICCP) is a standard data-exchange format that is widely used in the electric utility industry to communicate information among operating entities.

Background

ICCP data are exchanged among reliability coordinators in the NERC ISN. In addition, several intra-regional and intra-company networks use ICCP to provide data to reliability coordinators from operating entities within each reliability coordinator's footprint.

Questions[19] in the ICCP-specific data section of the NERC Real-Time Tools Survey address ICCP data-exchange management and methodology. The survey questions examine issues and practices that affect the adequacy, quality, and timeliness of data ultimately provided to real-time tools for analyzing the reliability of the bulk electric system.

Summary of Findings

The majority of respondents to the NERC Real-Time Tools survey rate ICCP-specific data as essential to conducting reliability assessments and maintaining situational awareness. In addition, ICCP data are also rated as essential to generating accurate state estimator solutions. However, analysis of survey responses identifies the following problems and issues related to ICCP data:

- a lack of availability of the systems that supply ICCP data, including, notably, data-link failures
- a lack of data coordination and quality
- an absence of documented processes and procedures for managing ICCP systems
- a lack of timely responses to requests for ICCP data updates
- an extended or unknown period of data latency
- restricted access to some data

Based on analysis of the Real-Time Tools Survey results, RTBPTF recommends the following new reliability standards:

- All TOPs must have ICCP or equivalent systems subject to the same standard as RCs.
- Data-exchange coordination requirements must be imposed.

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[19] RTBPTF relied extensively on the EPRI *Inter-Control Center Communications Protocol (ICCP) User's Guide* as a reference (EPRI TR-107176) to prepare survey questions.

- A requirement and measure of data-exchange-system reliability must be established.
- A minimum trouble-response time must be specified.
- Documented procedures must be established for activities such as data maintenance and update, data naming, and alarm response.
- ICCP systems must have redundant components to avoid data exchange interruptions.

The analysis of survey responses also reveals that systems equivalent to the NERC ISN are in use. Therefore, the task force recommendations should apply to both ISN and equivalent systems. The recommendations that follow the survey findings subsection below are written to apply to any type of data exchange system equivalent to the NERC ISN.

The task force does not recommend the creation of operating guidelines for ICCP data at this time.

The areas identified for more analysis include data latency, time skew, and time stamping and mapping of data to real-time tools.

The NERC Operating Reliability Subcommittee (ORS) specifically requested that RTBPTF investigate current practices of entities that exchange data via ICCP because of concerns about ICCP data quality and availability as well as ICCP's prevalence within the industry for exchanging operating reliability data.
The NERC Real-Time Tools Survey explores the various systems that survey respondents use to receive ICCP data. Approximately 50 percent (27 out of 55) of respondents report that they receive data through a direct connection to the ISN. In addition, more than 78 percent (43 out of 55) report that they also receive ICCP data via direct connections to other entities' systems, and approximately 45 percent (25 out of 55) receive ICCP data via data links internal to their companies. These results clearly show that equivalent systems are widely used in addition to the ISN. This finding has important bearing on the applicability of reliability standards governing data exchange. This issue is discussed further below in the subsection "Recommendations for New Reliability Standards."

The overwhelming majority, 75 percent (41 out of 55), of all respondents to the ICCP data section of the survey rate their ICCP data as "essential" for the value it adds to their situational awareness. All reliability coordinators rate ICCP data as "essential." The survey respondents make the following comments regarding the criticality of ICCP data:

> "Essential for state estimation and visual monitoring of non-owned areas."
>
> "ICCP data [are] essential for real-time security assessment."

> “In carrying out the RC role, ICCP information is required from BAs within [the] RC footprint.”
>
> “Our operators have tools that require ICCP data to work properly.”
>
> “The ICCP data [are] applied to the state estimator model to make the model observable in real-time.”
>
> “It [ICCP data] fills in holes in our data, provides backup on ties with neighbors, and provides a ‘wider’ view of the system.”

Although ICCP data are considered essential by the majority of survey respondents, the survey results reveal that these data are not consistently available in many cases. Approximately 58 percent (29 out of 50) of respondents have self-imposed availability requirements of 99 percent or higher for their ICCP systems. However, only 7 of the 13 RCs that have availability requirements report that they actually meet their own requirements.

ICCP data are used by most respondents (especially RCs) to perform state estimation. However, the survey responses indicate that ICCP system data-link failures rank highest on the list of ICCP-related problems affecting the ability of state estimators to generate a solution (see Table 1.2-1). One respondent made the following comment regarding the frustration resulting from losing a data link:

“Our biggest issue is with failure of entire ICCP data links from the data providing entity. We have issues with losing ICCP data from an entire utility on a periodic basis.”

The problem of ICCP data link failures is largely a result of lack of redundancy. Nearly one-third of all respondents (17 out of 53) report that they do not have redundant data links. Note that respondents report a higher level of redundancy for other aspects of their ICCP systems than for their data links. For example, nearly 90 percent (47 out of 53) of respondents have redundant ICCP servers, and nearly 78 percent (41 out of 53) have redundant network connections.

Other commonly reported ICCP-specific data problems that affect state estimator solutions include lack of maintenance coordination with other entities, poor data quality, and failover problems (see Table 1.2-1). One reason for frequent data coordination and quality problems is that fewer than half of the respondents (23 out of 49) have formal agreements with other entities that specify how data-set changes are to be communicated, coordinated, and tested. RTBPTF concludes that data-coordination requirements are necessary to alleviate many of the problems that affect state estimator solutions. These requirements will help ensure operators’ ability to assess transmission system reliability and maintain situational awareness.

ICCP Problems Impacting State Estimator Solutions	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Other	Total
Data Link failure on your end	X	X	X	X				X	X	X				X	X			19	**28**
Data Link failure on the other end	X	X	X	X	X	X	X	X	X	X		X	X	X	X	X		20	**35**
Invalid, failed, or corrupted data received	X	X	X	X	X	X	X	X	X		X	X						13	**24**
Failover Problems	X	X	X			X	X	X					X					7	**14**
Uncoordinated maintenance activities (in house)	X	X		X	X		X											5	**10**
Uncoordinated maintenance activities (external)	X	X	X			X	X			X	X							10	**17**
Data time skew (i.e., mixing stale ICCP data with fresh SCADA data)	X	X	X	X		X												2	**7**
Software bugs	X	X						X						X				5	**9**
Interoperability issues (i.e., version incompatibility, user object incompatibility)		X		X	X													5	**8**
Extended bad quality indication	X				X				X									3	**6**

Table 1.2-1 — ICCP Problems Impacting State Estimator Solutions[20]

Most respondents report that they have very few documented processes or procedures for managing their ICCP systems (see Table 1.2-2). Although approximately 65 percent (32 out of 49) of all respondents have documented data-naming conventions, less than half have data-maintenance procedures (23 out of 49) or documented EMS data-mapping standards (19 out of 49), and only about 25 percent have documented test procedures (14 out of 49) or documented procedures for monitoring and measuring data-link performance (12 out of 49) and data availability (13 out of 49). In addition, only 60 percent (16 out of 27) of all respondents that exchange ICCP data via the NERC ISN indicate that they have the NERC *Data Exchange Working Group (DEWG) ISN Node Responsibilities and Procedures Document* even though this document is posted on the NERC web site. Even RCs, who are generally considered to maintain more documentation than TOPs and BAs (see Table 1.2-2), report very little.

The survey was not designed to allow respondents to identify by name other entities that do not perform well in providing consistently accurate, timely, and up-to-date data sets via ICCP data exchange. Therefore, it is not possible to use the survey responses to determine a correlation between the type and quality of an entity's documentation of internal processes and procedures and that entity's performance of ICCP data exchange as judged by those with whom the entity

[20] RC responses are indicated with "X." Aliases are used as column headers to mask the RCs' names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, "RC 1" in any given table may not be the same as "RC 1" or the equivalent identifier in another table in this report.

exchanges data. Several entities (particularly RCs) that report that they exchange large quantities of data via ICCP and that are known by RTBPTF members to perform those functions reasonably well report having several different types of documented processes and procedures. Therefore, the task force concludes that the lack of a consistent set of documentation is a significant impediment to an entity's ability to maintain its ICCP data exchange.

Documented ICCP Processes and Procedures	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**RC17**	**Others**	**Total**
Data-naming conventions	X	X	X	X	X	X	X	X	X	X	X	X	X					17	**30**
EMS data-mapping standards	X	X	X	X	X	X	X		X	X	X			X				8	**19**
Data maintenance procedures	X	X	X	X	X	X	X	X		X	X	X						11	**22**
Troubleshooting guidelines or procedures	X	X	X	X	X		X	X	X	X								14	**23**
Test procedures	X	X		X	X	X	X				X		X					3	**11**
Data-set creation procedures	X	X	X	X			X	X	X			X						11	**19**
Data availability monitoring and measurement	X	X	X	X		X		X	X	X								4	**12**
NERC DEWG ISN node responsibilities and procedures document	X	X		X	X	X	X				X	X						6	**14**
Data-link performance monitoring and measurement	X	X	X		X	X							X					4	**10**
Fault management procedures (i.e., error statistics analysis, lost connection response)	X	X	X		X			X										2	**7**
Associated management procedures	X	X	X						X									5	**9**

Table 1.2-2 — Documented ICCP Processes and Procedures[21]

Another data-coordination and management problem identified in the survey is timeliness of responses to requests for data set updates. Respondents report a wide range of turn-around times for these requests. Very few respondents (4 out of 50) report receiving same-day service for data-set updates, and only 30 percent (15 out of 50) report that they usually receive a response within a week. Still others have to wait up to two weeks (6 out of 50) or even as long as a month (5 out of 50) for a data-set update. In addition, several respondents (18 out of 50) report that response times for data set update requests depend upon the particular data provider.

The survey asked several questions related to data latency and its effects, but the responses are inconclusive. When asked how long it takes from the time a data point changes in the field until that change is represented in their local EMS

[21] Reliability coordinator responses are indicated with "X." Aliases are used as column headers to mask the RCs' names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is "RC 1" in any given table may not be the same as "RC 1" or the equivalent identifier in another table in this report.

database (i.e. data latency), respondents report a broad range of data latency times ranging from a few seconds to a few minutes, and several do not know their data latency times (see Table 1.2-3). A few respondents identify time skew (defined here as the time difference between stale ICCP data and fresh SCADA data) as contributing to solution problems for their state estimators. Finally, the vast majority of respondents report that there are no time stamps on the ICCP data that they send (35 out of 51) or receive (27 out of 49). The task force concludes that more analysis and review of data latency and its impact on reliability assessment and situational awareness are needed before definitive minimum requirements can be established.

In Section 1.1, Telemetry Data, of this report, RTBPTF recommends decreasing the required update frequency for operational reliability data from 10 minutes to 10 seconds. If this recommendation is implemented, some data latency impacts should be reduced. However, unless "updates" are always made with fresh data (rather than simply forwarding old data to recipients every 10 seconds until fresh data are available from the source), there will be few improvements in data latency.

Analog Point Data Latency	***Responses***		**Status Point Data Latency**	***Responses***
< 4 seconds	4		< 4 seconds	5
< 10 seconds	4		< 10 seconds	14
< 30 seconds	16		< 30 seconds	8
< 1 minute	12		< 1 minute	6
< 5 minutes	4		< 5 minutes	5
10 minutes or less	0		10 minutes or less	2
Don't know	6		Don't know	7
Other	4		Other	3

Table 1.2-3 — ICCP Data Latency

NERC Reliability Standard TOP-005-0, Operational Reliability Information, requires RCs, TOPs, and BAs to provide data to one another for the purpose of performing operational reliability assessments and coordinating reliable operations unless otherwise agreed. Requests for these data are often rejected for a variety of reasons, as indicated in Tables 1.2-4 and 1.2-5. The survey results raise the question of whether this requirement is being consistently met. The task force concludes that the industry requires specification of what can be considered a legitimate restriction to data access.

Criteria Used by Respondents to Restrict Access to Data	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Permission from data owner	X	X	X	X	X	X	X	X			X			X		X		26	**37**
Justification of need by requestor	X	X	X	X	X	X	X		X	X		X						26	**36**
Market-sensitive data	X	X	X	X	X	X		X	X	X	X	X	X		X			19	**32**
Technical limitation (i.e., server size, communication bandwidth)	X	X																9	**11**
Resource limitation (i.e., maintenance/support overhead)																		6	**6**
Software license limitation																		5	**5**
None																		1	**1**

Table 1.2-4 — Criteria Used by Respondents to Restrict Access to Data

Suppliers' Constraints Restricting Respondents' Access to Data	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Permission from data owner	X	X	X	X	X	X		X		X		X						27	**36**
Justification of need not accepted by supplier	X	X	X	X	X		X		X									15	**22**
Market-sensitive data	X	X	X			X	X	X	X		X							20	**28**
Technical limitation (i.e., server size, communication bandwidth)	X																	7	**8**
Resource limitation (i.e., maintenance/support overhead)																		7	**7**
Software license limitation																		2	**2**
None													X	X	X	X		3	**7**

Table 1.2-5 — Suppliers' Restrictions on Respondents' Access to Data

Survey respondents identify operator awareness of ICCP system health as an important issue. Approximately 80 percent (41 out of 51) state that their system operators monitor the status of their ICCP data links. Approximately 70 percent (35 out of 51) of respondents provide audible alarms to make operators aware of ICCP system problems, and 50 percent (26 out of 51) have ICCP system "health" visualization displays for their operators. Operators must be quickly made aware when state estimator solutions may be unreliable because of ICCP data problems.

The August 14, 2003 *Outage Task Force Final Blackout Report* finds that the reliability data that MISO was receiving via the ECAR data network and other data links were not linked (mapped) so that MISO's state estimator could be automatically informed of status change of a key transmission line.[22] The Real-

[22] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. page 48.

Time Tools Survey explored this issue by asking respondents to quantify the ICCP status point data and ICCP analog data they receive that are mapped into respondents' real-time network application databases and used by these applications. The results are summarized in Tables 1.2-6 and 1.2-7. Most RCs, as expected, map a large percentage of the ICCP data they receive, as do many other respondents, but a few RCs and other respondents could improve in this area.

Mapping ICCP data to a real-time network model database often requires that the model be modified to provide sufficient detail to allow linking of specific data. For example, an external station represented as a bus-branch model will have to be expanded to include circuit breakers at the correct locations to permit mapping of specific breaker status points to the correct devices. This effort is resource intensive; resource constraints may have prevented some respondents from performing all of the mapping that they ultimately intend to accomplish. This could be one reason that some respondents report low mapping percentages (or do not reply to this question at all). The task force concludes that the specific data that should be mapped to real-time tools are dependent upon the NERC definitions of bulk electric system and wide-area view. As previously stated, the task force believes that these definitions are unclear. Therefore, the task force concludes that the issue of data mapping requires more analysis.

ICCP Status Point Data Mapped to Real-Time Tools	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC 17	Others	Total
All	X	X																15	**17**
> 90 percent			X	X	X	X	X	X	X	X	X	X						3	**13**
> 75 percent													X	X	X	X		2	**6**
> 50 percent																		1	**1**
> or = 25 percent																		1	**1**
< 25 percent																		3	**3**
None																		8	**8**
Unanswered																	X	5	**6**

Table 1.2-6 — ICCP Status Point Mapping

ICCP Analog Data Mapped to Real-Time Tools	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC 17	Others	Total
All	X	X																12	**14**
> 90 percent			X	X	X	X	X	X	X	X								5	**13**
> 75 percent											X	X	X	X	X			1	**6**
> 50 percent																X		1	**2**
> or = 25 percent																		2	**2**
< 25 percent																		3	**3**
none																		9	**9**
unanswered																	X	5	**6**

Table 1.2-7 — ICCP Analog Mapping

Survey respondents were asked to quantify how long it takes to resolve problems internal to their systems and how long it takes responsible external entities to respond to and resolve problems in those entities' systems. Table 1.2-8 summarizes the responses. A large majority, 76 percent (38 out of 50) of respondents, can resolve internal problems within one hour. Only 44 percent (22 out of 50) can get external problems resolved within one hour; however, 74 percent (37 out of 50) can get resolution within two hours. The task force concludes that these time frames are achievable and necessary thresholds for a trouble-response standard because of the importance of these data for maintaining reliability.

Trouble Response Time Range	*Internal Problems*		*External Problems*
< 1 hour	38		22
1-2 hours	6		15
2-4 hours	3		1
4-8 hours	2		7
> 1 day	0		1
Other(s)	1		4

Table 1.2-8 — ICCP Trouble-Response Times

Survey respondents report various methods for creating ICCP object IDs. Approximately 58 percent (29 out of 51) of respondents create globally unique data names used by all parties. Twenty-seven percent report using the object names provided by the source. Only about 12 percent (6 out of 51) of respondents generate sequential numbers for ICCP object IDs, and an overwhelming majority, 76 percent (38 out of 51), have a structured naming convention such as a composite key (i.e., Station ID + Device ID + Point ID, etc.). Recent discussions in the ISN community have identified data recipients' difficulty in keeping abreast of data-point name changes instituted by data providers. It is widely recognized that the names of data points utilizing a composite key naming convention are likely to change when some component of the name changes, such as when a station is renamed or a device is replaced with a different type of device (replacing a switch with a breaker, for example). By contrast, data points named with sequentially generated numbers are unlikely to need changing. Nevertheless, the Real-Time Tools Survey indicates that composite key names are much more common than sequential numbers, probably because data providers who create the names find it easier for purposes of data point checkout and testing to list data point details within the name. Despite these issues, the task force concludes that a standard naming convention would be difficult to implement and therefore does not recommend one. Instead, RTBPTF recommends that this issue be addressed in comprehensive standards governing all aspects of data-exchange coordination.

Recommendations for New Reliability Standards

Based on analysis of the Real-Time Tools Survey results, RTBPTF recommends the following:

- All transmission operators must be required to have ICCP or equivalent systems subject to the same standard as reliability coordinators.
- Data-exchange coordination requirements must be imposed.
- A requirement and measure of data-exchange-system reliability must be established.
- A minimum trouble-response time must be specified.
- Documented procedures must be established for activities such as data maintenance and update, data naming, and alarm response.

- ICCP systems must have redundant components to avoid data-exchange interruptions.

Each of these recommendations is described in detail below.

NERC Standard TOP-005-0, Operational Reliability Information, currently specifies several general requirements (R1 – R5) and one measure (M1) to "ensure reliability entities have the operating data needed to monitor system conditions within their areas." The requirements do not specify use of the ICCP protocol; however, requirement R3 refers as follows to the NERC ISN, which utilizes ICCP for data exchange:

> Upon request, each reliability coordinator shall, via the ISN or equivalent system, exchange with other Reliability Coordinators operating data that are necessary to allow the Reliability Coordinators to perform operational reliability assessments and coordinate reliable operations.

The results of the Real-Time Tools Survey indicate that several other regional networks over which operational reliability data are exchanged also use the ICCP protocol. The task force concludes that these regional networks should be considered "equivalent systems." Some other data-exchange arrangements do not use the ICCP protocol but arguably could be considered "equivalent systems." Requirement R3 of TOP-005-0 applies only to RCs; however, survey respondents clearly indicate, as noted in the Survey Findings section above, that ICCP data are essential for reliability assessment and situational awareness, including the ability to produce a state estimator solution. The task force concludes that ICCP and "equivalent systems" are critical reliability tools for both RCs and TOPs. Therefore, the task force recommends as follows.

RTBPTF Recommendation

> All Transmission Operators shall have ICCP or equivalent systems for data exchange and shall be subject to the same standards for this tool as reliability coordinators. Other responsible entities who are using ICCP or equivalent systems to support or complement their reliability coordinator's ability to operate the bulk electric system reliably in accordance with formal agreements, contracts, or established practices or procedures, shall be subject to the same standards for ICCP or equivalent systems as their reliability coordinator's.

The task force believes that this statement of applicability is also consistent with Requirement R3 of Reliability Standard IRO-002, Reliability Coordination – Facilities, which states:

> Each reliability coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data

exchange to other reliability coordinators or Transmission Operators and Balancing Authorities via a secure network.

Each of the following recommendations is written to apply to any type of data exchange system used to support compliance with NERC Reliability Standard TOP-005-0.

Recommendation – S4

Develop data-exchange standards

Data Exchange Coordination Standards

Survey respondents identify a number of issues related to ICCP data exchange, as noted in the Survey Findings section above.

RTBPTF Recommendation

RTBPTF recommends that new requirements be added to standard TOP-005 that apply to all users and providers of data exchanged by ICCP or equivalent systems. These requirements will standardize the procedures, processes, and rules governing:

- Interoperability of ICCP and equivalent systems
- Data access restrictions
- Data-naming conventions
- Change management and coordination
- Joint testing and data checkout
- Quality codes
- Dispute resolution

This recommendation is also related to the issue of change management procedures for real-time models, as discussed in Sections 4.1, Model Characteristics, and 4.2 Modeling Practices and Tools, of this report. The task force recognizes the work already completed by NERC DEWG in these areas, which is documented in the *ISN Node Responsibilities and Procedures Document*.[23] The task force considers this work a good starting point for definitive and comprehensive requirements. The task force recommends that the *ISN Node Responsibilities and Procedures Document*, which currently does not have the force and effect of a standard, evolve into a standard developed in accordance with the recommendations of this report.

[23] http://www.nerc.com/~filez/isn.html

Availability requirements

The survey respondents identify problems associated with failure/lack of availability of systems providing ICCP data, particularly failures of data links, which directly impact state estimator solutions. The task force recommends that NERC Standard TOP-005-0 be revised to incorporate a requirement and a metric for data-exchange system availability. The fact that many entities have self-imposed availability requirements is evidence of the desirability of such a metric. The revised standard should specify how availability is to be calculated and measured.

RTBPTF Recommendation

The task force recommends that each data recipient track the availability of data from each provider of ICCP or equivalent system data. Each time a data set is received, the recipient would calculate the ratio of the number of data points received with "good" quality codes to the total number of data points expected. This ratio should exceed 99 percent for 99 percent of the sampled periods (i.e., 10 seconds each) over a calendar month. In addition, this ratio should not be less than 99 percent for 30 consecutive minutes.

Requiring data recipients to calculate data availability will reveal problems affecting data quality or availability anywhere in the data stream. RTBPTF also recommends that data providers be required to monitor availability of internal data systems used to provide data to others. Recommended standards for data system availability monitoring are included in the general recommendations in Section 5.4, Critical Applications Monitoring, of this report.

The following diagram (Figure 1.2-1) is an example of the distribution of responsibilities for data availability calculation and monitoring.

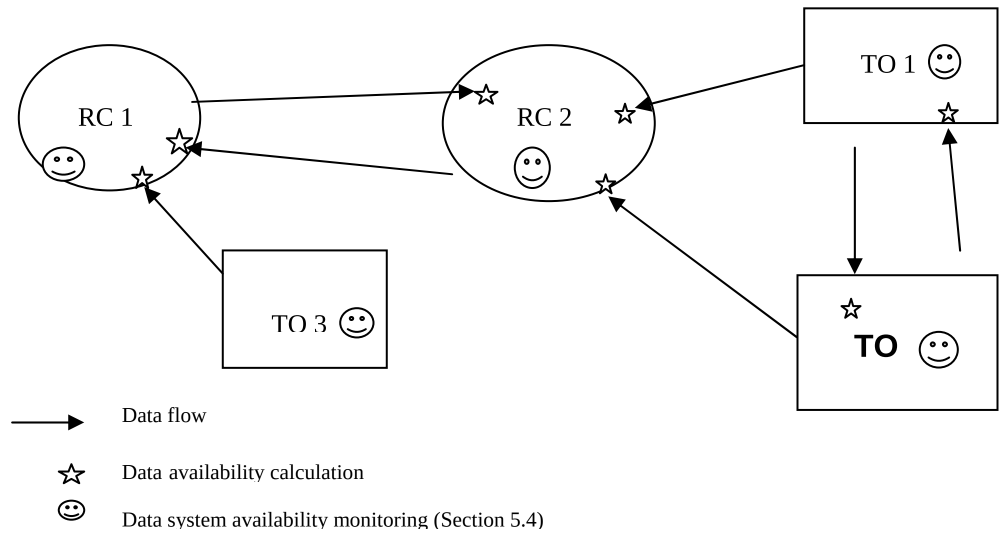

Figure 1.2-1 — Example of Data Distribution Responsibilities

Recommendation – S5

Develop data-availability standards and a process for trouble resolution and escalation

Trouble-response times

The internal and external trouble-response times reported by survey participants, as noted in the Survey Findings section above, are achievable thresholds for a trouble-response standard.

RTBPTF Recommendation

The task force recommends the establishment of minimum response times for the restoration of data exchange among control centers following the loss of a data link or other problems within the source system. These minimum requirements could be incorporated within the data-exchange coordination standards recommended above. Alternatively, minimum response times could be specifically defined as a new requirement and a new measure under NERC Standard TOP-005-0. In addition, the task force recommends the development of a trouble-resolution process that would be mandatory for all entities responsible for the management and maintenance of ICCP or equivalent systems that could be the cause of a loss of data-exchange capability with another system. These entities would be required to identify a mutually agreeable restoration target time with affected data recipients. The standard process would also include service restoration procedures and prioritization criteria.

Maintenance and management documentation

Most survey respondents possess very few documented procedures for managing their ICCP systems, as reported in the Survey Findings section above.
RTBPTF Recommendation
The task force recommends that all entities responsible for managing and maintaining ICCP or equivalent systems be required to have documented procedures for the support activities necessary to ensure compliance with the current and recommended requirements of NERC Standard TOP-005-0. At a minimum the following procedures and activities should be documented:

- Data maintenance and updates
- Testing
- System availability monitoring and measurement
- Troubleshooting
- EMS (real-time network applications) data-mapping standards
- Data-naming conventions
- Fault management (maintenance and display of error statistics)
- Alarm response

The task force recommends that NERC Standard TOP-005-0 be revised to incorporate a requirement and a measure for the above procedures. These procedures should be subject to self-certification and should be reviewed for completeness during the NERC compliance audits.

ICCP or equivalent system component redundancy

The Real-Time Tools Survey revealed a high degree of redundancy in respondents' ICCP systems. Note that redundant components support a high degree of system availability by ensuring that a single failure point will not make the system unavailable. The survey also revealed that some ICCP or equivalent systems did not have redundant data links. Many respondents identified the loss of a data link as a serious failure impacting the ability of their state estimators to produce accurate solutions.

RTBPTF Recommendation

Requirement R1.4 of NERC Reliability Standard COM-001-0, Telecommunications, requires that "where applicable" telecommunications facilities "shall be redundant and diversely routed." The task force recommends that this requirement be expanded to specifically state that it applies to ICCP and equivalent systems. The standard should also require that all system upgrades, expansions, and replacements include the elimination of single points of failure.

Recommendations for Operating Guidelines

RTBPTF does not recommend the development of new operating guidelines pertaining to ICCP or equivalent systems.

Areas Requiring More Analysis

RTBPTF concludes that time skew, time stamp, and data latency require additional analysis by NERC.

Recommendation – A1

Investigate the impact of time skew on state-estimator solution quality.

Time skew and time stamping

The impact of data time skew on state estimator solution quality has been the subject of various technical papers during the past several years. The survey responses related to time skew and data latency were too general to allow the task force to identify a specific requirement for maximum data latency or minimum time skew based upon actual (as opposed to theoretical) experience. More detailed investigation, testing, and analysis are necessary before any standards can be developed, including requirements for time stamping of ICCP data or equivalent system data.

The task force recommends that NERC DEWG be tasked with studying these issues with the goal of "informing" the standards-setting process and identifying cost-effective standards or operating guidelines that would minimize the impacts of stale data on real-time reliability analysis and situational awareness.

Additionally, the task force recommends that DEWG validate or confirm the task force's recommendation in Section 1.1, Telemetry Data, of this report to revise the timing requirements in Attachment 1 of NERC Standard TOP-005. DEWG should also consider the data update requirements (periodic or by exception) necessary to support the requirements in NERC Standard IRO-002. Special consideration should be given to the communication of event-driven system changes such as a transmission-line trip that RCs need to analyze in real time.

Recommendation – A2

Identify necessary fidelity and scope of real-time models and the extent of the requisite data-exchange sets.

Mapping of data to real-time tools

The specific data that an RC, TOP, or other entity responsible for reliability should request from neighboring or nearby entities and map into its real-time tools databases or models is a function of many variables. Among these variables are the size and location of the entity, the "footprint" for which the entity is responsible, and the view of the external area necessary to monitor and coordinate system operations reliably. These same variables affect the extent and fidelity of the real-time models that must be built and maintained in order to perform real-time functions such as state estimation and contingency (security) analysis. The necessary fidelity and scope of real-time models and the extent of the requisite data-exchange sets needed to map to the models are ultimately dependent upon the definitions of bulk electric system and wide-area view. Section 1.1, Telemetry Data, of this report discusses the need to clarify the definition of bulk electric system, and Section 2.1, Alarm Tools, discusses the definition of wide-area view. Furthermore, Sections 4.1, Model Characteristics, and 4.2, Modeling Practices and Tools, recommend additional analyses of modeling criteria, especially as those criteria apply to areas external to an entity's footprint. This analysis should also explore the criteria for determining what external measurements must be mapped into the portions of real-time models representing areas external to an entity's area of responsibility.

Examples of Excellence

RTBPTF cites an automated trouble-tracking system that includes processes and procedures for reporting, notification, tracking, resolution, and escalation of ICCP data problems used by Independent System Operator (ISO) New England and its transmission owners as an example of excellence (See EOE-2 in Appendix E).

RTBPTF cites an automated monitoring system that periodically compares data-set time stamps to detect and alarm any data sets that have stopped updating for any reason used by ISO New England and its transmission owners as an example of excellence (See EOE-3 in Appendix E).

Section 1.3
Miscellaneous Data

Definition

Miscellaneous data are used by real-time applications/tools that may not be supported by basic SCADA and/or ICCP systems. Miscellaneous data include information on weather such as that available from commercial data services as well as information from sources such as substation relays, recorders, and monitoring units.

Background

Chapter 7 of the *Outage Task Force Final Blackout Report* includes an examination of causal factors common to all major outages during the past 40 years.[24] One cause common to several events (although not the August 14 blackout) was severe weather conditions. Examples include lightning storms, extreme heat, and high winds. Even though the blackout that led to the creation of RTBPTF was not specifically weather related, the lack of situational awareness is a recurring theme in the blackout report. The task force believes that the issue of situational awareness from an operator's perspective would be inadequately addressed without an investigation of weather data and their application in control centers. The investigation of the other types of miscellaneous data documented in this section of the report is intended to uncover situational awareness issues that might be addressed by less common or less familiar data.

The Real-Time Tools Survey miscellaneous data section encompassed weather, fault locator, and high-speed sampled data.

Summary of Findings

Survey results reveal that almost all respondents rely to some extent on weather data and perceive these data as valuable for situational awareness; in contrast, respondents do not rely on fault locator data and high-speed sampled data (including phasor data) to monitor system conditions in real time and maintain reliability. Based on these findings, RTBPTF recommends modifying existing standards to require that weather data be provided to operators but does not recommend new standards for fault locator or high-speed sampled data. The task force notes, however, that phasor measurement data are part of other current industry initiatives, and that NERC's *Reliability Standards Development Plan: 2007-2009* includes the possibility of a new standard for PMUs.

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[24] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. pp. 107-110.

Meteorological Data

Almost all survey respondents rely on meteorological data to some extent. Nearly 90 percent (47 out of 53) of the respondents to this section of the survey reported using some type of meteorological data to support situational awareness. Approximately 38 percent (18 out of 47) of those who use this type of data consider it “essential” or required for situational awareness, and almost half (23 out of 47) consider it ”desirable” and an enhancement of their operational capabilities.

Survey comments indicate that many respondents use weather data to improve load forecasts and monitor potential impacts of severe weather on system reliability. Others use data such as temperature and wind speed to calculate thermal limits. Less common uses of meteorological data include forecasting expected wind-generation levels and determining when to expedite transmission-line maintenance outages. Table 1.3-1 summarizes the types of meteorological data currently being monitored and used in real-time tools.[25]

Monitored (M) / Used (U)	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others
Temperature	M/U	M	M/U	M/U	M/U	M	U	M	U	M/U	M	M						26/8
Wind Speed/Direction	M/U	M	M	M	M/U	M	M		U	M/U		M						21/4
Relative Humidity	M	M	M/U	M		M			U		M							16/3
Dew Point	M	M	M/U	M/U	M/U	M			U									6/2
Ice Thickness	M	M					U											4/0
Cloud Cover	M		M		M/U													11/2
Lightning Information	M					U	U	M										16/2
Precipitation	M	M		M				M										18/0

Table 1.3-1 — Meteorological Data Monitored (M) and Used (U) in Real-Time Tools

Survey respondents place high value on meteorological data for supporting real-time operational capabilities and situational awareness. The following comments by respondents highlight the perceived value of weather data:

> “Knowing weather conditions throughout the state is essential to system operations.”

[25] Aliases are used as column headers to mask RC-s’ names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, “RC 1” in any given table is not the same as “RC 1” or the equivalent identifier in another table in this report.

> “You cannot have an accurate load forecast without good weather data.”
>
> “Weather information is essential to understanding and preparing for activity on the system.”
>
> “Wind speed and lightning information is used in determining when to restore lines early, from maintenance outages.”
>
> “We use meteorological data to calculate thermal limits and to monitor thunderstorms and ice storms.”

The survey asked how meteorological data are presented to operators. Approximately 61 percent (28 out of 46) of respondents provide these data on dynamically updated, dedicated EMS displays, and about 24 percent (11 out of 46) have dynamically updated, multi-purpose dashboard displays to support situational awareness. Other less commonly used methods of data presentation include: periodic reports, cable television, weather services via the Internet, and corporate meteorological department intranet web pages.

Because of the perceived value and prevalent usage of meteorological data for situational awareness, RTBPTF recommends adding a new requirement to an existing standard to address the necessity of providing weather data to operators.

Fault Locator Data

Survey results generally reveal that, when a fault causes a facility outage, fault locator data facilitate restoration. Almost 60 percent (30 out of 51) of respondents use fault locator data, but only about 20 percent (4 out of 21) of those who do not use it plan to add it in the future. Only 6 respondents who use these data rate them “essential“ for situational awareness. All but one of the other users consider these data ”desirable” for situational awareness. The following comments by survey respondents indicate the perceived value of fault locator data:

> “Fault location data is required for effective restoration after an outage. Written procedures require fault location data before circuit tests are performed.”
>
> “Reduces repair time and facilitates quicker isolation and partial restoration.”
>
> “We use the distance data of the distance relay flagged in every line fault.”

The survey also asked how fault locator data are presented to operators. Of the users who responded to this question, approximately 58 percent (15 out of 26) provide these data on dynamically updated, dedicated EMS displays. None of the users employs dynamically updated, multi-purpose dashboard displays. The remainder of the users either have to dial up fault locator relays to obtain data or have support personnel obtain and pass along the information, i.e., in oral or written reports.

Fault locator data are narrowly used to facilitate restoration of an out-of-service facility. The data are not used to monitor system conditions in real time to maintain reliability or prevent or mitigate IROL or SOL violations. Therefore, RTBPTF does not recommend any new standards or requirements for fault locator information.

High-Speed Sampled Data

In general, survey results reveal that high-speed sampled data, such as sequence-of-events data and PMU data, are currently used primarily for post-event analysis rather than real-time operations. Approximately 40 percent (20 out of 51) of respondents use high-speed sampled data, and only about 39 percent (12 out of 31) of those who do not use this type of data plan to add it in the future. Only 2 of the respondents who use this type of data consider it ”essential” for situational awareness; 15 respondents consider these data ”desirable” for situational awareness. The following comments by survey respondents indicate the perceived value of high-speed sampled data:

> “Used as an assist in analysis of system problems.”
>
> “[Sequence of Events] data is not used by real-time operators, but by engineering staff for post-event analysis.”
>
> “Used for post event analysis.”
>
> “Enhances capabilities, but is not essential.”
>
> “[Respondent] is investigating ways of getting PMU data into real time.”

The survey also asked how high-speed sampled data are presented to operators. Of the users (18) who responded to this question, only 3 provide these data on dynamically updated, dedicated EMS displays or multi-purpose “dashboard” displays. Ten other users provide operators with written or on-line reports, and the others apparently provide the data only to engineering or other support staff.

High-speed sampled data are narrowly used for post-event analysis, not to monitor system conditions in real time to help maintain reliability or prevent or mitigate IROL or SOL violations. Therefore, RTBPTF does not recommend any new standards or requirements for these data. However, the task force notes that real-time application of PMU data is part of the scope of other industry initiatives such as the Eastern Interconnection Phasor Project,[26] and there is a placeholder in NERC's *Reliability Standards Development Plan: 2007-2009* for a new standard for PMUs. According to the NERC work plan, "Several industry studies were recently issued and these studies need to be analyzed to determine appropriate requirements for a NERC standard."[27]

Recommendations for New Reliability Standards

Currently, NERC Reliability Standards contain only two requirements related to weather data. Standard TOP-006-0, Monitoring System Conditions, has a requirement (R4) that "Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern." Also, Attachment 1 of Standard TOP-005-1, Operational Reliability Information, lists "severe weather" among the data that RCs, TOPs, and BAs are expected to provide to and share with one another. There are no measures for either of these requirements.

Recommendation – S6

Develop a new weather data requirement to situational awareness and real-time operational capabilities.

RTBPTF Recommendation

RTBPTF recommends[28] that a new requirement be added to Standard TOP-005-1 to address the importance of weather data for situational awareness and real-time operational capabilities.

PR1. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have dynamically updated real-time and forecasted weather data that are important to the operational capability and situational awareness of that particular entity so that operators can readily determine the current and near-term weather conditions that might affect monitoring or operation of their systems.

RTBPTF recommends the following measure for the requirement stated above:

PM1. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall document each type of weather data provided to operators and shall demonstrate the visualization tools or other means used to present these data to operators.

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[26] http://phasors.pnl.gov/
[27] *NERC Reliability Standards Development Plan: 2007-2009.* p. 210.
[28] Proposed requirements are designated "PR," and proposed measures are designated "PM."

Rationale

Real-Time Tools Survey results indicate that many respondents provide and use meteorological data for purposes other than forecasting load. Because meteorological data have become increasingly available in control centers and are commonly used to enhance situational awareness and support real-time operational capabilities, it is desirable and practical to “raise the bar” to ensure that all operators in all control centers have the weather information they need to do their jobs.

Weather varies considerably from region to region, and individual RCs, TOPs, and BAs tend to monitor the meteorological data that are most important to their specific needs. Therefore, the proposed requirement does not standardize the weather data to be collected but instead allows each entity to continue to determine which data are most important for its operators. Because a majority of survey respondents display weather data in a similar manner, using dynamically updated data on EMS displays or dashboard visualization or, at a minimum, commercial weather services available in the control center over cable television or the public Internet, mandating that operators receive dynamically updated real-time and forecasted data is consistent with prevailing practice.

Recommendations for Operating Guidelines

RTBPTF is not recommending Operating Guidelines related to Miscellaneous Data at this time.

Areas Requiring More Analysis

RTBPTF is not recommending additional areas for analysis related to Miscellaneous Data.

Examples of Excellence

RTBPTF did not identify any Examples of Excellence related to Miscellaneous Data.

Section 2.0
Reliability Tools for Situational Awareness

Introduction

RTBPTF formulated a list of real-time monitoring and analysis tools/applications commonly used by operators and inquired in the Real-Time Tools Survey about current industry practices associated with these tools.

The basis for the initial list was a report on minimum requirements and best practices for reliability software, presented at a FERC technical conference.[1] The report addressed the following functional areas:

- Network analysis
- Monitoring and visualization
- Real-time enablers
- Operations planning
- Transactions scheduling
- History and forecasting

RTBPTF first narrowed the scope of the list and limited the applications that the task force considered to real-time operator tools; that is, RTBPTF did not consider long-term, medium-term, day-ahead, and training tools even though these tools may be essential for reliability entities. The task force also did not consider real-time tools related to market or economic operations. Special emphasis was placed on real-time tools that could aid operator situational awareness (i.e., reliability tools) because the *Outage Task Force Final Blackout Report* repeatedly identifies operator situational awareness as a key element that needs improvement.

Next, RTBPTF used its collective expertise and experience to formulate a final list of tools to investigate and a precise definition for each. The Real-Time Tools Survey was designed so that different types of entities responsible for the reliable operation of the bulk electric system could describe their use of each tool, so the task force could use the survey results to characterize to the tool's status industry wide. The survey and the subsections below cover following real-time reliability tools for operators:

- **Section 2.1, Alarm Tools** — Alarm tools are applications that emit real-time visible and audible signals to alert operators to events and conditions affecting the state of the bulk electric system. Alarm tools

[1] Macedo, Frank. Consultant to FERC. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14.
http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

can be external, embedded within the SCADA/EMS system, or a combination of both.

- **Section 2.2, Visualization Techniques** — Visualization techniques are a group of user interface applications, tools, and displays that provide, for operators and others, concise visual monitoring and enhanced multiple views of relevant power system data in real time. Visualization techniques help operators monitor and understand system events and/or conditions in neighboring power systems that may affect reliable operations in the operator's portion of the power system.
- **Section 2.3, Network Topology Processor** — The network topology processor (NTP) is a SCADA-based application that determines facility status and station configuration based on breaker and switch status data. The processor converts a nodal network model into a bus-branch model, for use by other applications such as the state estimator. It may perform the same function for study network applications such as power flow.
- **Section 2.4, Topology & Analog Error Detection** — Topology and analog error detection identifies and/or automatically overrides incorrect SCADA breaker and switch statuses, which can support the NTP application and to improve the accuracy and robustness of the state estimator application. It may also identify and/or automatically ignore SCADA analog measurements that are unreasonable or inconsistent with network connectivity.
- **Section 2.5, State Estimator** — The state estimator application performs statistical analysis using a set of imperfect, redundant, telemetered power system data to determine the system's current condition. The system condition or state is a function of several variables: bus voltages, relative phase angles, and tap changing transformer positions. A state estimator can typically identify bad analog telemetry, estimate non-telemetered flows and voltages, and determine actual voltage and thermal violations in observable areas. The state estimator application provides a base case for reliability-analysis applications and input to other system monitoring tools. The state estimator solution is typically used as the base case for other reliability-related applications, such as contingency analysis. In some cases, the state estimator is used primarily as the basis for information communicated to operators regarding power system status; e.g., the state estimator drives the alarm application that alerts operators to power system events.

- **Section 2.6, Contingency Analysis** — The contingency analysis application analyzes the impact on system security of specific, simulated outages (lines, generators, or other equipment) or higher load, flow, or generation levels. Contingency analysis identifies problems such as line overloads or voltage violations that will occur if a new event (contingency) happens on the system. The state estimator solution is a representation of current system conditions and usually serves as the base case for contingency analysis. The information that contingency analysis generates enables RCs and TOPs to implement mitigation plans in advance of a contingent event such as a line trip. Contingency analysis is used as a real-time application as well as for studying potential scenarios.

- **Section 2.7, Critical Facility Loading Assessment (CFLA)** — A critical facility loading assessment (CFLA) evaluates a set of contingencies and then approximates the post-contingency loading of a set of monitored facilities using telemetered SCADA flows and line outage distribution factors (LODFs). CFLA may be used as a backup application if the state estimator and/or contingency analysis applications fail.
- **Section 2.8, Power Flow** — The power-flow application calculates the state of the electric power system in the form of flows, voltages, and angles, based on load, generation, net interchange, and facility status data. Power-flow applications are available in both on-line and off-line versions. An application that evaluates on-line power flow typically is incorporated into an EMS (or has a direct data feed from an EMS) and utilizes node-breaker topology whereas off-line power flow utilizes models of bus branches and static data. Section 2.8 addresses only on-line power flow.
- **Section 2.9, Study Real-Time Maintenance (SRTM)** — The SRTM function simulates real-time network applications (i.e., topology processor, state estimator, and contingency analysis) and debugs problems without affecting the real-time operation of the applications. An SRTM tool can be an on-line application integrated with the production EMS, an application integrated with a non-production EMS (development, test, dispatcher training simulator system, etc.), or an off-line application.
- **Section 2.10, Voltage Stability Assessment** — Voltage stability analysis (VSA) is an application that executes in near-real time and aids in the determination of system operating limits. VSA is based on an assessment that uses a current state estimator model of the real-time system. VSA may derive minimum voltages at key buses below which voltage collapse may occur under further stress to the system, evaluate whether sufficient stability margins exist for an analyzed base case, provide margins relative to particular stress modes such as transfers or system loading, or provide information on minimum dynamic reactive reserves required in local areas.

- **Section 2.11, Dynamic Stability Assessment** — Dynamic stability assessment (DSA) is an application (or suite of applications) executing in near-real time that aids in determining stability-related system operating limits using a current state estimator model of the real-time system. DSA may also indicate the dynamic stability margin for the most critical fault/contingency condition.
- **Section 2.12, Capacity Assessment** — The capacity assessment (or equivalent) application gives an overview of available generation capacity (MW or Mvar) in real time.
- **Section 2.13, Emergency Tools** — Emergency tools are applications or procedures that operators use when the power system enters or is about to enter an emergency. Several different types of emergency tools were considered in the Real-Time Tools Survey:
    - Residential Load Management or Residential Demand-Side Management tools, which allow curtailment of residential load demand for specific appliances
    - Commercial/Industrial Load Management or Commercial/Industrial Demand-Side Management tools, which allow curtailment of commercial/industrial load
    - Load Reduction by Voltage Reduction – curtailment of demand by voltage reduction on distribution loads
    - Rotating Load Shed – curtailment of demand by triggering/scheduling load shedding
- **Section 2.14, Other Tools (Current and Operational)** — This section reviews other tools (currently available and operational) that are not specifically addressed in the other sections. including:
    - Congestion Management Application - a tool for relieving network congestion within an entity's service territory using operational means within the entity's control authority, i.e., generation redispatch, curtailment of economy transactions within the entity's service area, switching in capacitor banks, opening low-voltage lines. Typically, congestion management is a security-constrained dispatch program, an optimal power-flow program, or an heuristic program that searches for the best solution from a set of options. For an ISO or an RTO, this may be part of the locational marginal pricing (LMP) application.
    - Inter-Regional Real-Time Coordination for Congestion Management Application - may be different from the congestion management application listed above if the entity uses a separate tool for managing congestion caused by transactions that originate and/or terminate outside of the entity's service area. This may also be the NERC Interchange Distribution

Calculator (IDC) if used for managing congestion that involves curtailing transactions outside of the entity's service territory.

- o Inter-Regional Real-Time Coordination for Market Redispatch – adjusts the market dispatch within the entity's service territory in coordination with adjacent reliability coordinators to manage inter-regional congestion in real time. This tool may be handled by the entity's congestion management application or through a different process.
- o Inter-Regional Voltage Profile Coordination — harmonizes the voltage profiles between two or more regions and may contain features such as wide-area voltage contour visualization, voltage schedule coordination between regions.
- o Short-Term Hydro Scheduling — manages, in real time, deviations from the long-term optimized schedule for reliability reasons (e.g., a response to a disturbance control standard event), acquiring support for localized voltage control.
- o Short-Term Wind Energy Forecasting — predicts and manages, in near-real time, generation accounting for variability of supply from wind energy sources.
- o Short-Term Load Forecasting — predicts short-term (next 0-60 minutes) loads based on parameters such as short-term weather effects, current load. Results could be used for predictive redispatch, look-ahead contingency analysis, awareness of scheduled non-conforming load changes, etc.
- o Short-Term Weather Forecasting — predicts short-term (next 0-60 minutes) extreme weather that may impact operations., i.e. lightning prediction tool, Doppler radar, etc.

Significance to the August 14, 2003 Blackout

The *Outage Task Force Final Blackout Report* concluded, and NERC concurred, that among the initiating causes of the 2003 blackout related to tools were:

- that FirstEnergy (FE) lost functionality of its critical monitoring tools and as a result lacked situational awareness of degraded conditions on its transmission system, and
- that the MISO RC did not provide adequate diagnostic support.

The *Outage Task Force Final Blackout Report* findings related to tools and operator situational awareness were the impetus for the formation of RTBPTF. The discussions of each tool that follows this introduction contain relevant background analysis and information from the *Outage Task Force Final Blackout Report*. For example, discussions that explain the directives given to FE and MISO related to the state estimator and contingency analysis are emphasized in the state estimator and contingency analysis sections below. The objective of these discussions is to introduce the reader to the significance of the RTBPTF recommendations as they relate to the *Outage Task Force Final Blackout Report* recommendations.

Tool Description and Usage

Each reliability tool (or set of tools) addressed in the Real-Time Tools Survey is described in detail in the following subsections. Each tool (or set of tools) is classified according to the industry's usage of it and its perceived importance for operator situational awareness. Most of the tools are commercially available and are generally used as intended. Discussions of each tool include the following:

- An assessment of the tool's availability within the respondent's organization (Is the tool available?)
- An assessment of the tool's usage (Is the tool operational?)
- An assessment of the tool's value for operator situational awareness and reliable operation of interconnected bulk electric system elements (How valuable is the tool for operators?)
- An assessment of the tool's general characteristics, algorithmic approaches, and functional features
- Description of available performance metrics for tool availability or tool solution quality (as applicable) and how they are assessed and used by survey respondents
- Description of the support and maintenance practices related to the tool

RTBPTF Recommendations for New Reliability Standards

RTBPTF approached each tool/application in the following way: given current NERC Reliability Standards how is the tool relevant in aiding operators in complying with monitoring and analysis requirements specified by the standards? Is the tool essential for operators to reliably manage the interconnected bulk electric system (i.e., should the tool be mandatory)?

Based on the survey results and current NERC Reliability Standards, RTBPTF recommends requiring the following monitoring and analysis tools for RCs and TOPs (illustrated in Figure 2.0-1 below):

- Alarm tools
- Telemetry data systems
- Network topology processor
- State estimator
- Contingency analysis

The rationale for recommending each tool as part of the minimum "Reliability Toolbox" is discussed in each of the tool's respective sections as well as in the Reliability Toolbox Rationale and Recommendation section near the beginning of this report. RTBPTF recommends requirements related to tool availability and solution quality (when applicable) for each of the mandatory tools listed above. RTBPTF believes that the mandatory tools listed above are essential for operators to maintain situational awareness and reliable operation of the bulk electric system. These essential tools are a mix of "monitoring" and "analysis" tools and are by no means the only tools that the operators that should use; RTBPTF believes that these are the *minimum* set of tools.

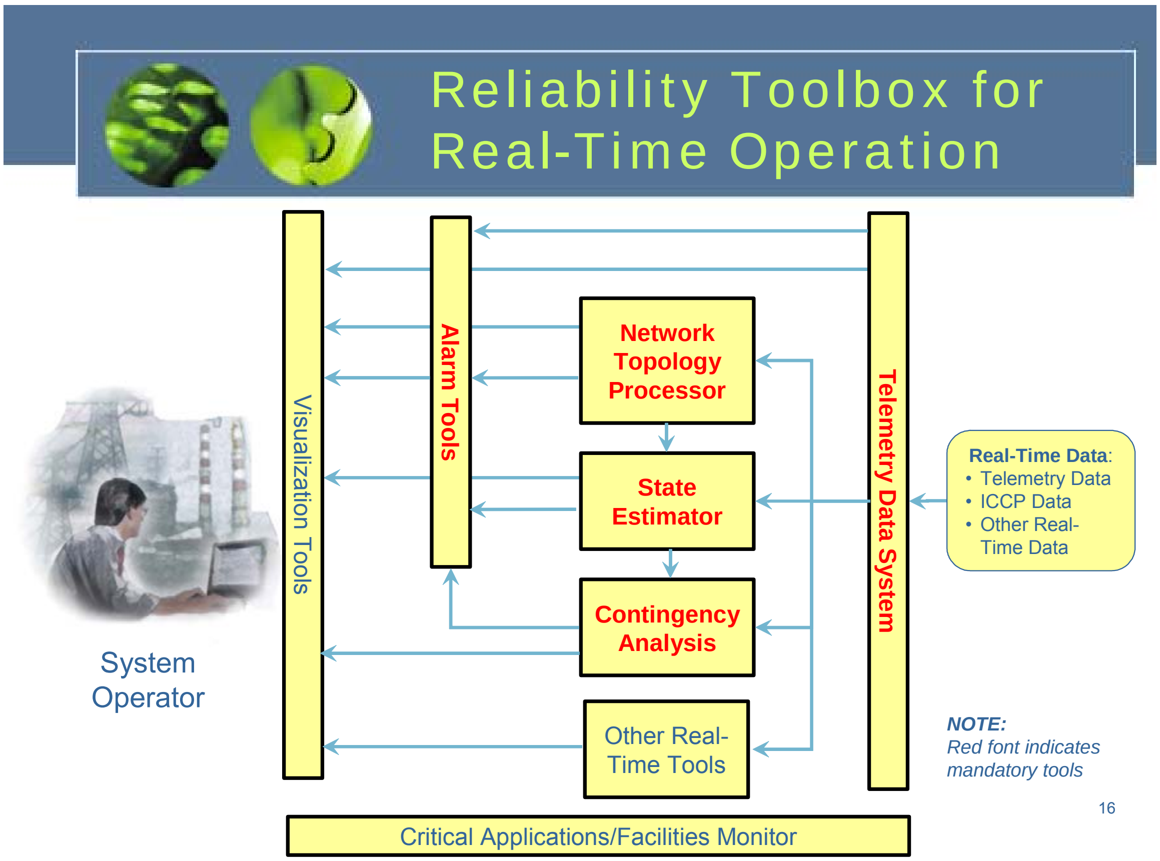

Figure 2.0-1 — The Reliability Toolbox

RTBPTF Recommendations for NERC Operating Guidelines

When there is a prevalent practice related to tool/application usage that supports a NERC Reliability Standard, a recommendation for Operating Guidelines is discussed in the relevant section of this report. In some cases, prevalent functional features that could aid operator situational awareness are recommended as Operating Guidelines.

Section 2.1
Alarm Tools

Definition

Alarm tools are applications that emit real-time visible and audible signals to alert operators to events and conditions affecting the state of the bulk electric system. Alarm tools can be external, embedded within the SCADA/EMS system, or a combination of both.

Background

The *Outage Task Force Final Blackout Report* stresses the importance of alarm tools, noting that "FE did not have additional or back-up monitoring tools to understand or visualize the status of their transmission system to facilitate its operators' understanding of transmission system conditions after the failure of their primary monitoring/alarming systems."[2]

The report analyzes FE'S computer problems in detail, with special emphasis on alarm tools. Excerpts of the analysis are quoted below:

> Starting around 14:14 [Eastern Daylight Time] EDT, FE's control room operators lost the alarm function that provided audible and visual indications when a significant piece of equipment changed from an acceptable to a problematic condition. Shortly thereafter, the EMS system lost a number of its remote control consoles. Next it lost the primary server computer that was hosting the alarm function, and then the backup server such that all functions that were being supported on these servers were stopped at 14:54 EDT. However, for over an hour no one in FE's control room grasped that their computer systems were not operating properly, even though FE's Information Technology support staff knew of the problems and were working to solve them, and the absence of alarms and other symptoms offered many clues to the operators of the EMS system's impaired state. Thus, without a functioning EMS or the knowledge that it had failed, FE's system operators remained unaware that their electrical system condition was beginning to degrade. Unknowingly, they used the outdated system condition information they did have to discount information from others about growing system problems.[3]

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[2] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. page 18.
[3] Ibid., page 52.

Alarm tools are essential for reliability monitoring; operators rely heavily on audible and on-screen alarms as well as alarm logs to detect significant changes in system conditions. The *Outage Task Force Final Blackout Report* observes that alarms are the fundamental means by which operators identify bulk electric system events that need attention. Without alarms, operators may not detect events that signal significant system changes.[4] RTBPTF identifies alarm tools as critical real-time tools. The alarm tools section of the Real-Time Tools Survey attempted to obtain a snapshot of current industry availability and usage of alarm tools.

Summary of Findings

The survey results indicate that nearly all survey respondents have operational alarm tools and consider them "essential" for situational awareness although just over half of all respondents can detect and independently notify operators and support staff when alarm tools are not functioning. Other key results are that the three most widely used functional features of alarm tools are conditional alarming, multiple areas of responsibility, and independent alarm acknowledgment. Survey results also reveal that the failed alarm processor detection feature is not commonly available

As illustrated in Table 2.1-1, nearly all survey respondents (52 out of 53) report that their organizations have operational alarm tools and that these tools are "essential" for situational awareness (50 out of 52). However, fewer than 60 percent of all respondents can detect and independently notify operators and support staff when alarm tools are not functioning.[5]

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, "32/38=84%" means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

[4] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. page 52.

[5] The issue of awareness of availability of critical real-time tools is addressed in Section 5.4, Critical Applications Monitoring.

Survey Question	All	RCs	Others
Do you have Alarm Tools?	53/53 = 100%	17/17 = 100%	36/36 = 100%
Are these tools operational?	52/53 = 98%	17/17 = 100%	35/36 = 97%
Do you rate the value (essential) of your Alarm Tools application(s) as a reliability tool for situational awareness?	50/52 = 96%	17/17 = 100%	33/35 = 94%
Do you rate the value (desirable) of your Alarm Tools application(s) as a reliability tool for situational awareness?	2/52 = 4%	0/17 = 0%	2/35 = 6%
Do you rate the value (minimal value) of your Alarm Tools application(s) as a reliability tool for situational awareness?	0/52= 0%	0/17 = 0%	0/35 = 0%
Do you rate the value (no value) of your Alarm Tools application(s) as a reliability tool for situational awareness?	0/52 = 0%	0/17 = 0%	0/35 = 0%

Table 2.1-1 — Availability and Rating of Alarm Tools

Control room personnel are the primary users of alarm tools. However, first-line management and EMS support staff also use alarm tools at a majority of the respondents' locations. System protection and control personnel, field personnel, and systems security personnel use alarm tools at some respondents' locations.

The most common input to alarm tools comes from SCADA/EMS systems, but other applications also provide input. Table 2.1-2 summarizes the most common applications that interface with alarm tools.

What Applications Are Interfaced or Integrated With Your Alarm Tools?	All	RCs	Others
Topology processor	28/52 = 54%	12/17 = 71%	16/35 = 46%
State estimator	32/52 = 62%	12/17 = 71%	20/35 = 47%
Contingency analysis	31/52 = 60%	12/17 = 71%	19/35 = 54%
Artificial intelligence or other high-level summary applications	8/52 = 15%	4/17 = 24%	4/35 = 11%
Station one-line displays	46/52 = 88%	13/17 = 76%	33/35 = 94%
Other(s)	9/52 = 17%	4/17 = 24%	5/35 = 14%

Table 2.1-2 — Applications Typically Interfaced to Alarm Tools

The Real-Time Tools Survey asked respondents to identify their alarm tools' available functional features and to rank the value of each functional feature for situational awareness. Table 2.1-3 summarizes the responses. Blank percentages equal zero.

Functional Feature	All	Reliability Coordinator	Others
Conditional Alarming: Ability to define conditions before issuing an alarm. For example, you would only alarm on a circuit breaker change of state if another circuit breaker is also open.	Available: 28/51=55% Operational: 19/28=68%	Available: 10/17=59% Operational: 9/10=90%	Available: 18/34=53% Operational: 10/18=56%
	Essential: 10/19=53% Desirable: 9/19=47% Minimal: No Value:	Essential: 6/9=67% Desirable: 3/9=33% Minimal: No Value:	Essential: 4/10=40% Desirable:6/10=60% Minimal: No Value:
Paging/Beeping Feature: Ability for the Alarm Tools to trigger pager or automatic cell phone paging	Available: 20/50=40% Operational: 14/19=74%	Available: 7/17=41% Operational: 4/7=57%	Available: 13/33=39% Operational: 10/12=83%
	Essential: 8/14=57% Desirable: 3/14=21% Minimal: 1/14=7% No Value: 2/14=14%	Essential: 3/4=75% Desirable: 1/4=25% Minimal: No Value:	Essential: 5/10=50% Desirable: 2/10=20% Minimal:1/10=10% No Value: 2/10=20%
Multiple Areas of Responsibility: Ability for the Alarm Tools to alarm a single event and deliver it to multiple Operators or multiple areas of responsibility	Available: 41/50=82% Operational: 36/41=88%	Available: 16/17=94% Operational: 14/16=88%	Available: 25/33=76% Operational: 22/25=88%
	Essential: 26/36=72% Desirable: 9/36=25% Minimal: 1/36=3% No Value:	Essential: 10/14=71% Desirable: 4/14=29% Minimal: No Value:	Essential: 16/22=73% Desirable: 5/22=23% Minimal: 1/22=1% No Value:
Independent Alarm Acknowledgment: Ability for Operators from multiple areas of responsibility to acknowledge their alarms independently even if the alarm came from a single event	Available: 26/50=52% Operational: 21/26=81%	Available: 9/17=53% Operational: 8/9=89%	Available: 17/33=52% Operational: 13/17=76%
	Essential: 15/21=71% Desirable: 6/21=29% Minimal: No Value:	Essential: 6/8=75% Desirable: 2/8=25% Minimal: No Value:	Essential: 9/13=69% Desirable: 4/13=31% Minimal: No Value:
Intelligent Alarm Processor: Ability to summarize alarms based on multiple conditions in order to simplify presentation to the Operator and add understanding to the significance of the current situation	Available: 17/50=34% Operational: 14/16=88%	Available: 6/17=35% Operational: 5/6=83%	Available: 11/33=33% Operational: 9/10=90%
	Essential: 10/15=67% Desirable: 4/15=27% Minimal: 1/15=7% No Value:	Essential: 4/5=80% Desirable: 1/5=20% Minimal: No Value:	Essential: 6/10=60% Desirable: 3/10=30% Minimal: 1/10=10% No Value:
Failed Alarm Processor Detection: Ability to detect and independently notify operators and support staff that the alarm processor or Alarm Tools are down and not functioning	Available: 28/49=57% Operational: 27/28=96%	Available: 7/17=41% Operational: 7/7 100%	Available: 21/32=66% Operational: 20/21=95%
	Essential: 22/27=81% Desirable: 4/27=15% Minimal: 1/27=4% No Value:	Essential: 6/7=86% Desirable: 1/7=14% Minimal: No Value:	Essential: 16/20=80% Desirable: 3/20=15% Minimal: 1/20=5% No Value:
Alarm Help Feature: Ability to directly access response procedures from the alarms	Available: 12/49=24% Operational: 11/12=92%	Available: 5/17=29% Operational: 4/5=80%	Available: 7/32=22% Operational: 7/7=100%
	Essential: 3/11=27% Desirable: 8/11=73% Minimal: No Value:	Essential: 1/4=25% Desirable: 3/4=75% Minimal: No Value:	Essential: 2/7=29% Desirable: 5/7=71% Minimal: No Value:

Table 2.1-3 — Functional Features of Alarm Tools

Three functional features are most widely used and identified by most respondents as either “essential” or “desirable” for situational awareness:

- Conditional Alarming — This feature allows the tool to define conditions before issuing an alarm. Eighty-eight percent of respondents who have conditional alarming available use this feature. All users of this feature rate it “essential” (53 percent) or “desirable” (47 percent) for situational awareness.
- Multiple Areas of Responsibility — This feature allows the tool to deliver a single event alarm to multiple operators or multiple areas of responsibility. Sixty-eight percent of respondents who have the multiple areas of

responsibility feature available use it. Most users of this feature (72 percent) rate it “essential” for situational awareness.

- Independent Alarm Acknowledgment — This feature allows operators from multiple areas of responsibility to acknowledge alarms independently even if an alarm came from a single event. Sixty-eight percent of respondents who have the independent alarm acknowledgment feature available use it. Most users of this feature (71 percent) rate it “essential” for situational awareness.

It is somewhat surprising to note that the failed alarm processor detection feature is not commonly available despite the *Outage Task Force Final Blackout Report*’s implicit recognition of the importance of this feature. Most respondents who have this feature available rate it “essential” for situational awareness (81 percent). This functionality is discussed further in Section 5.4, Critical Applications Monitoring.

Recommendations for New Reliability Standards

Alarm tools are essential, providing visual and audible signals in real time to alert operators and others to events affecting the state of the bulk electric system. Alarms may be initiated by information transmitted directly from telemetry data systems or from other applications, such as the state estimator and contingency analysis. Alarms are an essential means of conveying situational awareness to operators. Accordingly, RTBPTF recommends modifications to existing standards to clarify that use of these tools is mandatory (see the Reliability Toolbox Rationale and Recommendation section). The discussions below support RTBPTF’s recommendation to make alarm tools mandatory.

Recommendation – S1

Mandate the following reliability tools as mandatory monitoring and analysis tools

- Alarm Tools
- Telemetry Data Systems
- Network Topology Processor
- State Estimator
- Contingency Analysis

Alarm Tools: Mandatory Monitoring and Analysis Tool

The *Outage Task Force Final Blackout Report* succinctly states the importance of alarm tools:[6]

[6] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. page 52.

> Alarms are a critical function of an EMS, and EMS-generated alarms are the fundamental means by which system operators identify events on the power system that need their attention. Without alarms, events indicating one or more significant system changes can occur but remain undetected by the operator. If an energy management system's alarms are absent, but operators are aware of the situation and the remainder of the its functions are intact, the operators can potentially continue to use the EMS to monitor and exercise control of their power system. In such circumstances, the operators would have to do so via repetitive, continuous manual scanning of numerous data and status points located within the multitude of individual displays available within their EMS. Further, it would be difficult for the operator to identify quickly the most relevant of the many screens available.

Existing NERC reliability standards implicitly assume the use of alarm tools to aid RCs and TOPs in maintaining situational awareness for the bulk electricity system. Specifying alarm tools as part of the Reliability Toolbox[7] eliminates the vagueness in current NERC reliability standards regarding whether alarm tools, as defined, are mandatory.

Recommendation – S7

Specify and measure minimum availability for alarm tools

Alarm tools availability

If alarm tools are mandatory for bulk electric system situational awareness, they must be highly available and redundant. Awareness of alarm tools availability is discussed in the recommendations in Section 5.4, Critical Applications Monitoring. However, a more detailed awareness (via a requirement for alarm tools availability) of alarm tools is necessary than is described in Section 5.4; in particular, awareness of any "stalled" state is critical. The *Outage Task Force Final Blackout Report* states, "[a]fter that time, the FE control room consoles did not receive any further alarms, nor were there any alarms being printed or posted on the EMS's alarm logging facilities. Power system operators rely heavily on audible and on-screen alarms, plus alarm logs, to reveal any significant changes in their system's conditions. After 14:14 EDT on August 14, FE's operators were working under a significant handicap without these tools. However, they were in further jeopardy because they did not know that they were operating without alarms, so that they did not realize that system conditions were changing."[8]

[7] See the Reliability Tool Box Rationale and Recommendation section.
[8] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. page 52.

RTBPTF recommendation

RTBPTF recommends adding the following new requirement to Standard TOP-006 in order to measure alarm tools availability:

> PR1. Alarm Tools Availability. Each reliability coordinator and transmission operator shall operate its alarm tools such that the alarm tools shall have at least one test alarm (or "watchdog" alarm) generated and processed at the Telemetry Data System scan rate. This test alarm (or "watchdog" alarm) could originate from a test field device or could be application generated.

Although the NERC standards process might address other factors in considering this recommendation, RTBPTF recommends the following measure for the requirement stated above:

> PM1. Each reliability coordinator and transmission operator shall maintain alarm logs demonstrating that the responsible entity's alarm tools application processed test alarms ("watchdog" alarms) according to Requirement PR2.

Rationale

Analysis of the alarm problem encountered by FE during the 2003 blackout suggests that FE's alarm tools essentially "stalled" while processing alarm events; that is, the alarm tools failed to complete the processing of alarms or produce any other valid output. In the meantime, new inputs — system condition data that needed to be reviewed for possible alarms — built up in and then overflowed the input buffers of the process.[9]

RTBPTF believes that a requirement should be established to correct the situation described above; specifically, an alarm tools availability metric should be required to complement the recommendations in Section 5.4, Critical Applications Monitoring.

Recommendation – G1

Identify implementation strategies and specific algorithms for conditional alarming.

Recommendations for New Operating Guidelines

Based on the survey results, three alarm tools features are most commonly used and identified by most respondents as "essential" or "desirable" for situational

[9] Ibid, Pages 53–54.

awareness. Because one of these features, conditional alarming, could easily be implemented similarly by different entities, “rules” for conditional alarming could be included in an operating guideline. The operating guideline for conditional alarming should identify implementation strategies and specific algorithms that could improve the alarms being sent to operators. The “rules” for conditional alarming need to be determined by studying prevailing industry practices before any operating guidelines are set for alarm tools.

The other two commonly used alarm tools features (multiple areas of responsibility and independent alarm acknowledgment) would most likely be customized to the needs of each entity, so a general operating guideline would be of little or no value. The implementation of these features would vary widely depending on the implementation of areas of responsibility of an entity.

Recommendation – A3

Study intelligent alarm processing capability for producing a single accurate view of system status.

Areas Requiring More Analysis

Macedo (2004)[10] identifies as a minimum requirement for alarm tools intelligent alarm processing that allows the application to filter, prioritize, and group alarms. RTBPTF perceives filtering, prioritization, and grouping of alarms as essential features that are inherent in industry-wide tools as defined in this section and understands intelligent alarm processing as an advanced feature that uses algorithms (i.e. artificial intelligence, neural networks) to process raw alarms and identify root causes of alarm avalanches. This functional feature produces compact, simplified alarm information for operators. RTBPTF recommends additional analysis of the industry’s intelligent alarm processing capability because survey results indicate that this seemingly essential feature is not commonly used.

The conditional alarming feature could be classified as an elementary form of intelligent alarm processing. As noted above, intelligent alarm processing allows the tool to summarize alarms based on multiple conditions to simplify presentation to the operator and clarify the significance of a current situation. Depending on the level of complexity of monitoring of entity’s area of responsibility, a feature such as intelligent alarm processing could aid operators in timely assessment of and response to complex situations. Processed alarms could give operators a single accurate view of system status so that they would

[10] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

not have to sift through numerous alarms simultaneously. Intelligent alarm processing is currently in use (34 percent of the Real-Time Tools Survey participants have this feature available). A barrier to wide use of this feature could be the difficulty of setting it up (i.e., the difficulty of maintaining the intelligent database of event processing as underlying system topology is modified). RTBPTF proposes that research in the area of intelligent alarm processing be conducted as the basis for practical implementation of this feature by the industry.

Examples of Excellence

The RTBPTF did not identify any Examples of Excellence related to alarm tools.

Section 2.2
Visualization Techniques

Definition

Visualization techniques are a group of user interface applications, tools, or displays that provide concise visual monitoring and enhanced multiple views of relevant power system data in real time to operators and others. Visualization techniques help an operator monitor and understand system events and/or conditions across neighboring power systems that may be affecting reliable operations in the operator's portion of the power system.

Background

The purpose of the visualization techniques section of the Real-Time Tools Survey was to determine typical industry practices or implementation by RCs, TOPs, and BAs of operational visualization tools. The survey attempted to obtain a snapshot of the current state of the industry regarding the availability and usage of certain types of visualization tools. The survey gave special emphasis to the types of visualization tools available to view/monitor bulk electric system elements currently used by reliability entities.

This section of the report summarizes findings from the Real-Time Tools Survey concerning visualization tools. The objective of this summary is to identify the visualization tools that are in wide use and their functionalities. This section also addresses the definition of the terms "wide area" and "wide area view" in the context of existing NERC reliability standards.[11] RTBPTF introduces the concept of the "view-area view boundary," defined as the network model boundary for the "wide area." The task force recommends that NERC establish a uniform formal process to define what constitutes bulk electric system elements included in the "wide area" and corresponding processes to define the "wide area view boundary."

RTBPTF recommends specific modifications to existing IRO and TOP reliability standards that require the use of visualization tools as part of compliance measures for existing NERC reliability standards. RTBPTF also recommends areas requiring further analysis related to the use, technology forums, and development of visualization tools for operators.

Visualization Tools and the 2004 Blackout

The *Outage Task Force Final Blackout Report* concludes that the August 14, 2003 blackout was similar in many ways to previous large-scale blackouts. The

[11] "Wide area" is defined in the NERC Glossary, which can be found at: http://www.nerc.com.

2003 blackout repeated many deficiencies identified in studies of prior large-scale blackouts, including poor vegetation management and operator training practices and a lack of adequate tools to allow operators to visualize system conditions.

The report states that the principal cause of the August 14, 2003 blackout was a lack of situational awareness, which was, in turn, the result of inadequate reliability tools and backup capabilities. The need for improved visualization capabilities over a wide geographic area is a recurrent theme in the blackout investigation. The report also notes that some wide-area tools to aid situational awareness (i.e., real-time phasor measurement systems) have been tested in some regions but are not yet in general use. Improvements in this area will require significant new investments involving existing or emerging technologies.

In the *Outage Task Force Final Blackout Report*, causal analysis of the blackout concludes that FE lacked situational awareness of transmission-line outages and degraded conditions on its own power system. This lack of situational awareness prevented FE system operators from taking corrective actions to return the system to within limits and from notifying MISO and neighboring systems of the degraded system conditions and loss of critical functionality in the control center. One cause for the lack of situational awareness was attributed to FE operators not having an effective alternative by means of which they could easily visualize the overall conditions of the system once their alarm tools application failed. An alternative for readily visualizing overall system conditions, including the status of critical facilities, would have enabled FE operators to become aware of forced transmission-line outages in a timely manner even though the alarms were non-functional. The report also indicates that MISO did not have monitoring tools that provided high-level visualization of the system. A high-level monitoring tool would have enabled MISO operators to view degrading conditions in the FE power system. A dynamic mapboard or other type of display could have provided a system status overview that could have been quickly and easily understood by the operators of both entities.

Chapter 10 of *Outage Task Force Final Blackout Report* presents recommendations to prevent or minimize the scope of future blackouts. The report identifies direct causes and contributing factors that include "inadequate regional-scale visibility over the bulk power system[12] and recommends that NERC evaluate and adopt better real-time tools for operators and reliability coordinators (Recommendation 22). The report further recommends that NERC require that its operating committee give particular attention in its report to the development of guidance to BAs and RCs on the use of automated wide-area visualization display systems and the integrity of data used in those systems. The report identifies a need for improved visualization techniques and intelligent software to analyze conditions, prioritize issues, and recommend actions. These

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[12] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April. p. 140

technologies should address some of the human factor issues that currently affect control room operators.[13]

Summary of Findings

The survey results indicate that most respondents use visualization tools and consider them essential for situational awareness, but that practice and implementation of visualization tools vary.

The description of findings below addresses the different visualization tools that were reported in the survey.

The results of the Real-Time Tools Survey reveal varying degrees of practice and implementation related to visualization tools. Use of visualization tools is prevalent in the industry (96 percent of the respondents indicated that they have some form of visualization tools), as shown in Table 2.2-1.

Respondent Type	Percentage That Have Visualization Tools Available
All	47/49=96%
RC	17/17=100%
Others	30/32=94%

Table 2.2-1 — Availability of Visualization Tools

As illustrated in Table 2.2-2, the majority of respondents (46/47=98 percent) indicated that they have an operational visualization tools application. Respondents having an operational visualization tools application were asked about the value of their respective visualization tools application as a reliability tool for situational awareness.

[13] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 159

Respondent Type	Percentage That Have Operational Visualization Tools	Value Placed on Visualization Tools for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	46/47=98%	38/46=83%	8/46=17%
RC	16/17=94%	15/16=94%	1/16=6%
Others	30/30=100%	23/30=77%	7/30=23%

Table 2.2-2 — Usage and Value of Visualization Tools by Entity Type

The majority of respondents that reported that they have operational visualization tools rated the value of their tools in enhancing situational awareness as either "essential" (83 percent) or "desirable" (17 percent). One respondent commented, "[c]lear concise information is mandatory for proper operator response." There are various types of visualization tools in use by reliability entities to monitor bulk electric system elements and parameters. Visualization tools allow operators to avoid directly viewing large amounts of raw data (telemetry or other real-time reliability tool/application-type data) directly so that operators can efficiently respond to power system problems. Visualization tools organize critical reliability parameters, which allow operators to monitor the information more efficiently.

The methods that visualization tools use to process and display critical reliability parameters depend on information resulting from the processing of raw data. The Real-Time Tools Survey inquired about certain types of visualization tools but did not by any means include a comprehensive list of the different types of visualization tools available to operators. Respondents were also given a chance to describe their own versions of visualization tools if their tools did not fit in any of the types specified in the survey and if their own versions of the tool were worth noting as an example of excellence.

According to the survey results, the data most commonly used by visualization tools are SCADA-type (i.e., telemetry data) data, followed by state estimator-type data. Respondents identified the following types of visualization tools:

- SCADA one-line displays
- State estimator one-line displays
- Study area one-line displays
- Dynamic overview displays
- Dynamic mapboards
- Wide-area visualization tools
- Selectable data trending

- Reactive reserve monitors[14]
- Remedial action scheme (RAS) monitors
- Automatic safety nets
- Transaction impact monitors
- Flowgate monitors

These types of visualization tools are described and discussed in the subsections below.

SCADA One-Line Displays

SCADA one-line displays are dynamic, one-line diagram displays of substations and major power system components that present the real-time status and selected flow, voltage, and other power system data. This is the most common type of visualization tool used today to monitor bulk electric system elements or parameters. Most entities (98 percent) having operational SCADA one-line displays rate this type of visualization tool "essential" (98 percent) for enhancing situational awareness. Table 2.2-3 summarizes the survey results for SCADA one-line displays by respondent type.

Respondent Type	Percentage That Have Operational SCADA One-Line Displays	Value of SCADA One-Line Displays for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	47/48=98%	46/47=98%	1/47=2%
RC	16/16=100%	16/16=100%	0/16=0%
Others	31/32=97%	30/31=97%	0/31=0%

Table 2.2-3 — Usage and Value of SCADA One-Line Displays by Respondent Type

The majority of respondents (91 percent) noted that their operators view SCADA one-line displays using proprietary SCADA/EMS terminals. Although not as prevalent, web-based SCADA one-line displays, either through a limited private network (28 percent) or through the entity's corporate intranet (19 percent), provide an alternative method of viewing SCADA one-line displays. SCADA/EMS support staff construct most SCADA one-line displays manually using a display editor (91 percent); a minority of entities (17 percent) use

[14] The original name for this type of visualization tool (per the Real-Time Tools Survey) was "Dynamic Reactive Reserve Monitoring" although the intent of this type of visualization was to monitor both dynamic and static sources. Therefore, to eliminate confusion, RTBPTF changed the name of this tool to "reactive reserve monitor" throughout this report.

applications that auto-generate the SCADA one-line displays using a vendor-provided default format.

The survey results indicate that SCADA one-line displays also have the following prevalent characteristics:

- Status values can be overridden by the operator through these displays.
- Analog values can be overridden by the operator through these displays
- Dynamic coloring is used for 1) indicating points in the alarms, 2) switching device positions, 3) indicating bus, line, and transformer statuses, and 4) indicating equipment clearance tags.
- Links are used to navigate to the master index or other one-line displays.
- The displays show SCADA quality codes on status and analog points.
- Although this feature is not as common, important procedures can be linked to selected displays.

Various Types of SCADA One-Line Displays

The survey asked respondents to quantify the relative number ("all," "most," "some," or "none") of SCADA one-line displays that are available for stations within the respondent's area of responsibility. There are various types of SCADA one-line displays (including summary displays that use SCADA data), and the survey asked respondents to quantify each type. Table 2.2-4 summarizes the responses for each type of display. The responses indicate the most common types of SCADA one-line displays currently used across the industry. The results correlate to the availability of telemetry data (see Section 1.1) needed for the type of SCADA one-line display.

Type of SCADA One-Line Display	What One-Line Displays are Available for Stations Within Your Area of Responsibility?			
	All	Most	Some	None
SCADA one-line for substations connected at 345-765 kV	38/43=88%			5/43=12%
SCADA one-line for substations connected at 100-230 kV	41/45=91%	4/45=9%		
SCADA one-line for substations connected at below 100 kV	21/46=46%	16/46=35%	7/46=15%	2/46=4%
Summary display(s) showing important flow gates at all substations	21/42=50%	3/42=7%	6/42=14%	12/42=29%
SCADA one-line for generation plants connected at 345-765 kV	36/42=86%			6/42=14%
SCADA one-line for generation plants connected at 100-230 kV	42/45=93%	1/45=2%	1/45=2%	1/45=2%
SCADA one-line for generation plants connected at below 100 kV	32/46=70%	8/46=17%	4/46=9%	2/46=4%
Summary display(s) showing generation from all sources in the area	32/46=70%	9/46=20%	3/46=7%	2/46=4%
Summary display(s) showing switched reactive devices from all sources	33/46=72%	7/46=15%	4/46=9%	2/46=4%

Table 2.2-4 — Summary of Responses — Relative Number of SCADA One-Line Displays Available for Stations Within Respondents' Areas of Responsibility

Table 2.2-5 illustrates the results for RCs, which are relatively similar to those from the general population.

Type of SCADA One-Line Display	What One-Line Displays are Available for Stations Within Your Area of Responsibility?			
	All	Most	Some	None
SCADA One-Line for Substations Connected at 345-765 kV	15/15=100%			
SCADA One-Line for Substations Connected at 100-230 kV	14/16=88%	2/16=13%		
SCADA One-Line for Substations Connected at below 100 kV	6/16=38%	5/16=31%	4/16=25%	1/16=/6%
Summary display(s) showing important flow gates at all substations	9/16=56%	3/16=19%	2/16=13%	2/16=13%
SCADA One-Line for Generation Plants Connected at 345-765 kV	15/15=100%			
SCADA One-Line for Generation Plants Connected at 100-230 kV	15/16=94%		1/16=6%	
SCADA One-Line for Generation Plants Connected at below 100 kV	12/16=75%	2/16=13%=	2/16=13%	
Summary display(s) showing generation from all sources in the area	12/16=75%	2/16=13%=	1/16=/6%	1/16=6%
Summary display(s) showing switched reactive devices from all sources	10/16=63%	2/16=13%	3/16=19%	1/16=6%

Table 2.2-5 — Summary of Responses — Relative Number of SCADA One-Line Displays Available for Stations within the RC's Area of Responsibility

Respondents were also asked to quantify the relative number of SCADA one-line displays available for stations in the areas adjacent to the respondent's area of responsibility. There are various types of SCADA one-line displays, including summary displays; entities were asked to quantify each type. Table 2.2-6 summarizes the responses for each type. Overall, there are fewer representations of bulk electric system elements on SCADA one-line displays of the areas adjacent to respondents' areas of responsibility compared to representations of locations within respondents' areas of responsibility. Table 2.2-7 summarizes the data for RCs.

Type of SCADA One-Line Display	What One-Line Displays are Available for Stations in the Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
SCADA one-line for substations connected at 345-765 kV	11/43=26%	5/43=12%	20/43=47%	7/43=16%
SCADA one-line for substations connected at 100-230 kV	6/44=14%	6/44=14%	26/44=59%	6/44=14%
SCADA one-line for substations connected at below 100 kV	4/44=9%	4/44=9%	13/44=30%	23/44=52%
Summary display(s) showing important flow gates at all substations	5/41=12%	5/41=12%	10/41=24%	21/41=51%
SCADA one-line for generation plants connected at 345-765 kV	11/44=25%	3/44=7%	14/44=32%	16/44=36%
SCADA one-line for generation plants connected at 100-230 kV	7/44=16%	6/44=14%	17/44=39%	14/44=32%
SCADA one-line for generation plants connected at below 100 kV	6/45=13%	1/45=2%	14/45=31%	24/45=53%
Summary display(s) showing generation from all sources in the area	5/44=11%	5/44=11%	5/44=11%	29/44=66%
Summary display(s) showing switched reactive devices from all sources	6/44=14%		6/44=14%	32/44=73%

Table 2.2-6 — Summary of Responses — Relative Number of SCADA One-Line Displays Available for Stations in Areas Adjacent to Respondents' Areas of Responsibility

Type of SCADA One-Line Display	What One-Line Displays are Available for Stations in the Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
SCADA One-Line for Substations Connected at 345-765 kV	5/14=36%	3/14=21%	5/14=36%	1/14=7%
SCADA One-Line for Substations Connected at 100-230 kV	2/14=14%	4/14=29%	7/14=50%	1/14=7%
SCADA One-Line for Substations Connected at below 100 kV	2/14=14%	1/14=7%	3/14=21%	8/14=57%
Summary display(s) showing important flow gates at all substations	4/14=29	2/14=14%	6/14=43%	2/14=14%
SCADA One-Line for Generation Plants Connected at 345-765 kV	7/15=47%	2/15=13%	5/15=33%	1/15=7%
SCADA One-Line for Generation Plants Connected at 100-230 kV	6/15=40%	3/15=20%	5/15=33%	1/15=7%
SCADA One-Line for Generation Plants Connected at below 100 kV	4/15=27%	1/15=7%	5/15=33%	5/15=33%
Summary display(s) showing generation from all sources in the area	2/15=13%	3/15=20%	3/15=20%	7/15=47%
Summary display(s) showing switched reactive devices from all sources	2/15=13%		4/15=27%	9/15=60%

Table 2.2-7 — Summary of Responses — Relative Number of SCADA One-Line Displays Available for Stations in Areas Adjacent to RC's Area of Responsibility

Various Types of Data Displayed on SCADA One-Line Displays

Respondents were asked to quantify the relative numbers of the types of data shown in their SCADA one-line displays for stations located within their area of responsibility. Various types of data are linked to SCADA one-line displays; respondents were asked to quantify the relative number of each data type. Table 2.2-8 summarizes the responses for each data type. The responses indicate the most common types of data linked to SCADA one-line displays across the industry. Breaker statutes and transmission MW/Mvar flows are the most common types of data shown in typical SCADA one-line displays.

Type of Data Displayed in SCADA One-Line Display	What Types of Data are Displayed on One-Line Displays for Stations Located Within Your Area of Responsibility?			
	All	Most	Some	None
Telemetered Breaker/Switch Position (open/close)	35/46=76%	11/46=24%		
Non-telemetered Breaker/Switch Position (open/close)	25/44=57%	18/44=41%		1/44=2%
Bus Voltage Magnitudes	25/46=54%	21/46=46%		
Bus Voltage Phase Angles	2/42=5%	4/42=10%	8/42=19%	28/42=67%
Line End Voltages (synchronizing potential on open line)	12/45=27%	10/45=22%	18/45=40%	5/45=11%
Ampere Flow on Lines and Transformers	13/44=30%	8/44=18%	11/44=25%	12/44=27%
Ampere Flow on Switching Devices	4/44=9%	6/44=14%	17/44=39%	17/44=39%
MW and Mvar flow On Lines and Transformers	22/46=48%	23/46=50%	1/46=2%	
Thermal and Voltage Operating Limits/Ratings	15/45=33%	9/45=20%	6/45=13%	15/45=33%
Incidental Station Alarms (entry, battery, transformer temperature, etc)	11/46=24%	12/46=26%	7/46=15%	16/ 46=35%

Table 2.2-8 — Summary of Responses — Types of data in SCADA One-Line Displays for Stations within Respondents' Areas of Responsibility

State Estimator One-line Displays

State estimator one-line displays are dynamic, one-line diagram displays of substations and major system components that present the state estimator solution for status and selected flow, voltage, and other power system data. Seventy-two percent of respondents have operational state estimator one-line displays. Respondents that have operational state estimator one-line displays rate this type of visualization tool either as “essential” (62%) or “desirable” (38%) for situational awareness. Table 2.2-9 summarizes the results of the survey for one-line displays by entity type. Most respondents view state estimator one-line displays using proprietary SCADA/EMS terminals, and most state estimator one-line displays are constructed from the existing SCADA one-line displays or manually by EMS support staff.

Respondent Type	Percentage That Have Operational State Estimator One-Line Displays	Value of State Estimator One-Line Displays for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	33/46=72%	18/29=62%	11/29=38%
RC	16/16=100%	12/16=75%	4/16=25%
Others	17/30=57%	6/13=46%	5/14=36%

Table 2.2-9 — Usage and Value of the State Estimator One-Line Displays by Respondent

The survey results indicate that state estimator one-line displays have the following prevalent characteristics:

- Status values can be overridden by the operator through these displays.
- Analog values can be overridden by the operator through these displays.
- Some entities link the state estimator residual values on their state estimator one-line displays.
- Dynamic coloring is used for 1) indicating points in alarm, 2) switching device positions, and 3) indicating bus, line, and transformer statuses.
- Links are used to navigate to the master index or other one-line displays.
- The displays show SCADA quality codes on status and analog points as processed by the state estimator.
- Although this feature is not as common, important procedures are linked to selected displays

Study Area One-line Displays

Study area one-line displays are one-line diagram displays of substations and major system components that present the active study context[15] of status and selected flow, voltage, and other data from the power system model in use. Examples of this type of visualization tool are power-flow one-line displays and contingency analysis one-line displays (for a specified contingency). Seventy-three percent of respondents have operational study area one-line displays. Respondents that have operational study area one-line displays rate this type of visualization tool as either "essential" (70 percent) or "desirable" (30 percent) for situational awareness. Table 2.2-10 summarizes the survey results of for study area one-line displays, by respondent type.

[15] Study context pertains to the output solution of certain power system network applications such as power flow, contingency analysis, etc.

Respondent Type	Percentage That Have Operational Study Area One-Line Displays	Value of Study Area One-Line Displays for Enhancing Situational Awareness	
		"Essential"	**"Desirable"**
All	32/44=73%	21/30=70%	9/30=30%
RC	16/16=100%	12/16=75%	4/16=25%
Others	16/28=57%	9/14=64%	5/14=36%

Table 2.2-10 — Usage and Value of Study Area One-Line Displays by Respondent Type

Study area one-line displays have these prevalent characteristics:

- Study context status values can be changed by the operator through these displays.
- Study context analog values can be changed by the operator through these displays
- Study context solution can be executed by the operator from these displays.
- Dynamic coloring is used for 1) indicating points in alarm, 2) switching device positions, and 3) indicating bus, line, and transformer statuses.
- Links are used to navigate to the master index or other one-line displays.

Dynamic Overview Displays

Dynamic overview displays are one-line and other graphical displays depicting the state, loading, and/or voltage levels over the wider area (or a sub-area within the entity's internal footprint) of the power system. Dynamic overview displays are essentially large SCADA one-line displays. An example of this type of visualization tool is area overview one-line displays, a one-line display that shows a group of electrically connected substations for a specified area. Eighty-two percent of respondents have operational dynamic overview displays. Respondents rate this type of visualization tool as "essential" (56 percent), "desirable" (42 percent), or of "minimal value" (3 percent) for situational awareness. Table 2.2-11 reflects the survey results for dynamic overview displays, by respondent type.

Respondent Type	Percentage That Have Operational Dynamic Overview Displays	Value of Dynamic Overview Displays for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	36/44=82%	20/36=56%	15/36=42%
RC	16/16=100%	9/16=56%	7/16=44%
Others	20/28=71%	11/20=55%	8/20=40%

Table 2.2-11 —Usage and Value of Dynamic Overview Displays by Respondent Type

Dynamic overview displays have these prevalent characteristics:

- Layered zooming with automatic de-cluttering
- Animated power flow (magnitudes and direction)
- Dynamic coloring for indicating real-time bus, line, and transformer status
- Navigational links to the master index or one-line displays
- Availability for telemetered (SCADA) output
- Continuous projection or display in large format for system operators
- Inclusion of boundary substations/plants adjacent to entity's area of responsibility

The survey asked respondents to quantify the relative number of power system elements (within the entity's area of responsibility) displayed in their dynamic overview displays. Table 2.2-12 summarizes the responses. The responses indicate the level of detail of dynamic overview displays across the industry.

Power System Element	What Power System Elements Within Your Area of Responsibility are Displayed on the System Overview?			
	All	Most	Some	None
Lines operating at 345-765 kV	28/33=85%	2/33=6%	1/33=3%	2/33=6%
Lines operating at 100-230 kV	24/35=69%	6/35=17%	5/35=14%	
Lines operating at below 100 kV	9/35=26%	8/35=23%	5/35=14%	13/35=37%
Transmission level intertie transformer banks	14/34=41%	5/34=15%	7/34=21%	8/34=24%
Transmission level capacitor/reactor banks	19/35=54%	5/35=14%	3/35=9%	8/35=23%
Generation plants 500 MW	24/33=73%	3/33=9%	2/33=6%	4/33=12%
Generation plants 100-500 MW	25/35=71%	2/35=6%	4/35=11%	4/35=11%
Generation plants < 100 MW	16/34=47%	6/34=18%	6/34=18%	6/34=18%
Substation switching devices on lines and transformers	7/33=21%	9/33=27%	8/33=24%	9/33=27%
Substation bus voltages	11/35=31%	18/35=51%	6/35=17%	
Line and transformer flows (MW and MVAR)	9/35=26%	20/35=57%	5/35=14%	1/35=3%

Table 2.2-12 — Summary of Responses — Type of Power System Element included in Dynamic Overview Displays

Dynamic Mapboard

A dynamic mapboard is a stationary, prominently located physical collection of painted lines, status lights, and analog readouts presenting continuous real-time status of important selected components of the power system to operators. It is "dynamic" because the status data for important selected components of the power system are updated in real time. A dynamic mapboard usually complements common SCADA/EMS displays. Sixty-five percent of survey respondents report that they have a dynamic mapboard and rate this type of visualization tool as "essential" while an additional 35 percent rate it "desirable" for enhancing situational awareness. Table 2.2-13 summarizes the survey results for the dynamic mapboard by respondent type. The Real-Time Tools Survey did not ask any questions regarding the extent of the entity's footprint displayed using the dynamic mapboard.

Some respondents indicated in comments that, in lieu of a dynamic mapboard, they use video projection technology (see wide-area visualization tools below) to show the same type of information to their operators.

Respondent Type	Percentage That Have Operational Dynamic Mapboard	Value of Dynamic Mapboard for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	28/43=65%	17/26=65%	9/26=35%
RC	10/15=67%	5/8=63%	3/8=38%
Others	18/28=64%	12/18=55%	6/18=33%

Table 2.2-13 — Usage and Value of Dynamic Mapboard by Respondent Type

A dynamic mapboard has these prevalent characteristics:

- Mosaic structure for easy accommodations of revisions/changes
- Color/lighting dynamics indicating breaker/switch status
- Digital readouts for presenting critical voltage or flow information
- Availability for telemetered output
- Maintenance of last known state/values if data link and/or SCADA/EMS fails
- Inclusion of boundary substations/plants adjacent to entity's area of responsibility

Wide-Area Visualization Tools

Wide-area visualization tools consist of displays/tools driven by SCADA, EMS, PMU, disturbance recorder, and other technical data collected in real time that present concise information for the "wide area." In general, these display/tools show multiple views of the status of critical facilities within the entity's internal footprint, but they are also used to show views of critical facilities or data from the entity's external footprint that have the potential to adversely impact the internal system (i.e., they cover the "wide area" as defined by the NERC Glossary, which can be viewed at: http://www.nerc.com). Under this definition, dynamic overview displays may be considered wide-area visualization tools. In addition to the traditional SCADA/EMS displays that show critical reliability parameters, wide-area visualization tools use other forms of technology/methodology to present vast amounts of information in a form that allows the operator to quickly and intuitively assess the state of the system. Examples of wide-area visualization technology/techniques include:

- Video or other forms of "big screen" or projection technology (usually in lieu of a traditional dynamic mapboard)
- Smart dashboards (i.e., wide-area status summary displays that show composite data from various applications/tools)
- Displays with extensive animation (i.e., line-flow visualization)[16]
- Contour displays (used to show spatially distributed continuous data)
- Virtual environment visualization[17]
- Data-mining systems[18]

Fifty-two percent of respondents report that they have wide-area visualization tools and rate these tools as either "essential" (55 percent) or "desirable" (45 percent) for enhancing situational awareness. Table 2.2-14 summarizes the survey results for wide-area visualization tools by respondent type.

[16] See http://www.pserc.wisc.edu/ecow/get/publicatio/1999public/etrep05Smaller.pdf
[17] Ibid.
[18] See http://www.infres.enst.fr/~hebrail/publications/hdr/Compstat_2000.pdf

Respondent Type	Percentage That Have Operational Wide-Area Visualization Tools	Value of Wide-Area Visualization Tools for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	23/44=52%	12/22=55%	10/22=45%
RC	14/16=88%	10/14=71%	4/14=29%
Others	9/28=32%	2/8=25%	6/8=75%

Table 2.2-14 — Usage and Value of Wide-Area Visualization Tools by Respondent Type

The survey also asked entities how they currently use their wide-area visualization tools for monitoring. Table 2.2-15 summarizes the responses.

What Types of Wide-Area Visualization Tools are Available in Your Application(s)?	Respondent Type		
	All	RC	Others
Frequency monitoring	18/22=82%	11/14=79%	7/8= 88%
Natural gas pipeline monitoring	1/22=5%	1/14=7%	0/8=0%
Inter-area phase angle separation monitoring	1/22=5%	0/14=0%	1/8=12%
Multi-area ACE monitoring	13/22=59%	11/14=79%	2/8=25%
Network topology island monitoring	8/22=36%	5/14=36%	3/8=38%
State estimator observable island monitoring	2/22=9%	2/14=14%	0/8=0%
High-speed phasor measurement monitoring	1/22=5%	1/14=7%	0/8=0%
System phase angle monitoring	2/22=9%	1/14=7%	1/8=12%
Voltage profile monitoring	14/22=64%	9/14=64%	5/8=63%
Multi-input artificial intelligence alarming and notification	1/22=5%	1/14=7%	0/8=0%

Table 2.2-15 — Wide-Area Visualization Tools — Current Implementation

The most prevalent uses for wide-area visualization tools are for frequency monitoring, multi-area ACE monitoring, and voltage profile monitoring. The Real-Time Tools Survey did not ask about details or methodology related to how the information is presented to operators. As noted in the Areas Requiring Further Analysis section below, RTBPTF recommends further research and analysis in the usage/implementation of wide-area visualization tools.

Selectable Data Trending

Selectable data trending is a type of visualization tool that can plot graphically selected power system values, using up-to-date data on the plot at a reasonable refresh rate. The majority of survey respondents (91 percent) report that they have selectable data trending and rate this type of visualization tool "essential"

(65 percent) or “desirable” (35 percent) for enhancing situational awareness. According to the survey, actual and/or historical/archived SCADA and application data are the most common types of data represented. Table 2.2-16 summarizes the survey results for selectable data trending by respondent type.

Respondent Type	Percentage That Have Operational Selectable Data Trending	Value of Selectable Data Trending for Enhancing Situational Awareness	
		“Essential”	“Desirable”
All	39/43=91%	18/36=50%	17/36=47%
RC	15/15=100%	8/15=53%	7/15=47%
Others	14/28=50%	10/21=48%	10/21=48%

Table 2.2-16 — Usage and Value of Selectable Data Trending, by Respondent Type

Reactive Reserve Monitor

A reactive reserve monitor uses static and dynamic sources to monitor reactive reserves in local geographic areas or major load centers. This tool can alarm the operator when a generating unit has reached its reactive capability or an area has approached the minimum reactive reserve requirement.[19] This type of tool could also function as the real-time user-interface representation of the documented procedures, practices, or guidelines for maintaining awareness of current and near-term reactive reserve capability (see Section 3.1, Reserve Monitoring). Only 35 percent of respondents report having a reactive reserve monitor tool available for their operators although 59 percent rate it “essential” for situational awareness (see Table 2.2-17).

[19] RTBPTF identifies the minimum reactive reserve requirement as an issue. See Section 3.1, Reserve Monitoring, for this discussion.

Respondent Type	Percentage That Have Operational Reactive Reserve Monitor	Value of Reactive Reserve Monitor for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	15/43=35%	7/13=54%	5/13=38%
RC	5/15=33%	3/5=60%	2/5=40%
Others	10/28=36%	4/8=50%	3/8=38%

Table 2.2-17 — Usage and Value of Reactive Reserve Monitor, by Respondent Type

Although use of this type of visualization tool is not prevalent, it is worth noting the survey results that identified some of the functional features of reactive reserve monitors, as shown in Table 2.2-18.

Functional Features of Reactive Reserve Monitors	Respondent Type		
	All	RC	Others
Available in study mode	3/14=21%	2/5=40%	1/9=11%
Available in real time	14/14=100%	5/5=100%	9/9=100%
Reserves are monitored area wide	9/14=64%	3/5=60%	6/9=67%
Reserves are monitored intra-area around load center	8/14=57%	4/5=80%	4/9=44%
Unit reactive limits are automatically adjusted based on reactive capability curves and MW output	9/14=64%	3/5=60%	6/9=67%
Unit reactive capability curves are adjusted in real time based on telemetry from the plant	5/14=36%	2/5=40%	3/9=33%
Static reactive capacity of shunt devices is automatically adjusted for real-time voltage	6/14=43%	3/5=60%	3/9=33%
Lagging reserves (total of unused capacitors, etc.) are calculated	9/14=64%	4/5=80%	5/9=56%
Leading reserves (total of unused reactors, etc.) are calculated	5/14=36%	3/5=60%	2/9=22%
Issues an alarm when an area/zone approaches its minimum reactive reserve	7/14=50%	4/5=80%	3/9=33%
Issues an alarm when a unit approaches its minimum/maximum reactive capability	4/14=29%	1/5=20%	3/9=33%
Voltage collapse calculations are part of this tool	2/14=14%	1/5=20%	1/9=11%
Area/Zone reactive demand includes load, loss, and charging Mvar for state estimator solutions	2/14=14%	2/5=40%	0/9=0%
Transmission-level capacitors and reactors are included in reserve calculations	9/14=64%	4/5=80%	5/9=56%
Low-voltage and customer-connected capacitors are included in reserve calculations	1/14=7%	1/5=20%	0/9=0%
Customer-connected motor load and distributed generation are included in reserve calculations	0/14=0%	0/5=0%	0/9=0%

Table 2.2-18 — Functional Features of Reactive Reserve Monitor

Remedial Action Scheme (RAS) Monitor[20]

A remedial action scheme (RAS) monitor provides tools/displays that allow operators to monitor the status of critical power system parameters, measure the proximity of these parameters to the triggering conditions for SPSs or total system failure, and alarms and advises operators regarding actions required to mitigate the pending power system condition. This tool is not in common use; only 38 percent of respondents indicate that they have this capability. However, in contrast to the whole population of respondents, 80 percent of RCs indicate that they have this type of tool available. Respondents that have an operational RAS monitor rate this tool as either "essential" (83 percent) or "desirable" (17 percent) for enhancing situational awareness (see Table 2.2-19).

Respondent Type	Percentage That Have Operational RAS Monitor	Value of RAS Monitor for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	16/42=38%	12/15=80%	3/15=20%
RC	12/15=80%	9/11=82%	2/11=18%
Others	4/27=15%	3/4=75%	1/4=25%

Table 2.2-19 — Usage and Value of RAS Monitor, by Respondent Type

RAS monitors are not prevalently used. However, it is worth noting the survey results regarding the functional features of this tool. Table 2.2-20 summarizes the survey results.

[20] The terminology was changed from the survey so as not to confuse it with "Remedial Action Scheme" as defined in the glossary section of the "Reliability Standards for the Bulk Electric Systems of North America" document.

Functional Features of RAS Monitor	Type of Respondent		
	All	RC	Others
Operators view the results of this application from SCADA/EMS displays	13/15=87%	9/11=82%	4/4=100%
Operators view the results of this application from other systems	4/15=27%	2/11=18%	2/4=50%
Operators can disable impending SPS based on determination that triggering conditions are false	3/15=20%	2/11=18%	1/4=25%
Alarms and results are based on real-time conditions	11/15=73%	7/11=64%	4/4=100%
Alarms and results are also based on contingency analysis	7/15=47%	6/11=55%	1/4=25%
Static, canned messages are used to inform the operator of recommended action	3/15=20%	2/11=18%	1/4=25%
Artificial Intelligence or multi-level heuristics are used to inform the operator of recommended actions	1/15=7%	1/11=9%	0/4=0%

Table 2.2-20 — Functional Features of RAS Monitor

Automatic Safety Net

An automatic safety net provides the tools/displays for operators to monitor, initiate, or disable triggering of schemes that shed firm load for under-voltage or under-frequency conditions. An automatic safety net could work with a RAS monitor. The automatic safety net is not a prevalent tool; only 37 percent of respondents indicate that they have this tool. Respondents that have operational automatic safety net visualization tools rate them as either "essential" (75 percent) or "desirable" (25 percent) for enhancing situational awareness (see Table 2.2-21).

Respondent Type	Percentage That Have an Operational Automatic Safety Net Visualization Tool	Value of Automatic Safety Net Visualization for Enhancing Situational Awareness	
		Essential	Desirable
All	16/43=37%	10/14=71%	4/14=29%
RC	4/15=27%	4/4=100%	0/4=0%
Others	8/28=29%	6/8=75%	2/8=25%

Table 2.2-21 — Usage and Value of Automatic Safety Net, by Respondent Type

Although the automatic safety net visualization tool is not prevalently used, it is worth noting the survey results regarding the functional features of this tool, which are summarized in Table 2.2-22.

Functional Features an Automatic Safety Net Visualization Tool	Respondent Type		
	All	RC	Others
Warning alarms are issued as conditions approach triggering (if time permits)	8/12=67%	2/4=50%	6/8=75%
Tripping points can be remotely disabled/enabled individually	6/12=50%	3/4=75%	3/8=38%
Tripping points can be remotely disabled/enabled in large groups	5/12=42%	3/4=75%	2/8=25%
Tripping points and/or boundaries are automatically changed as conditions merit	2/12=17%	1/4=25%	1/8=12%

Table 2.2-22 — Functional Features of Automatic Safety Net

Transaction Impact Monitor

A transaction impact monitor provides the tools/displays for operators to monitor scheduled transactions and interchange flows between BAs. The majority (72 percent) of survey respondents indicate that they have this type of tool. Respondents that have an operational transaction impact monitor rate this tool as either "essential" (82 percent), "desirable" (12 percent), or of "minimal" value (5 percent) for enhancing situational awareness. Current implementations of transaction impact monitors use real-time displays, updated for every schedule change. Table 2.2-23 summarizes the results of the survey for transaction impact monitors.

Respondent Type	Percentage That Have Operational Transaction Impact Monitor	Value of Transaction Impact Monitor for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	28/42=67%	20/27=74%	5/27=19%
RC	14/16=88%	11/14=79%	2/14=14%
Others	14/26=48%	9/13=69%	3/13=23%

Table 2.2-23 — Usage and Value of the Transaction Impact Monitor, by Respondent Type

Flowgate Monitor

A flowgate monitor provides the tools/displays for operators to monitor actual and contingency flows on designated flowgates. The NERC Glossary defines "flowgate" as "[a] designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions." This type of visualization tool provides flowgate information to operators; it could run either within or independent of SCADA/EMS systems. Fifty-nine percent of all respondents indicate that they have a flowgate monitor; eighty-one percent of RCs indicate that they have this feature available. Respondents that have an operational flowgate monitor rate this tool as either “essential” (88 percent) or “desirable” (13 percent) for enhancing situational awareness. As currently implemented across the industry, flowgate monitors display real-time data and generate alarms for predicted flowgate overloads. Table 2.2-24 summarizes the results of the survey for flowgate monitors.

Respondent Type	Percentage That Have an Operational Flowgate Monitor	Value of Flowgate Monitor for Enhancing Situational Awareness	
		“Essential”	“Desirable”
All	25/43=58%	21/24=88%	3/24=13%
RC	13/16=81%	12/13=92%	1/13=8%
Others	12/27=44%	9/11=82%	2/11=18

Table 2.2-24 — Usage and Value of Flowgate Monitor, by Respondent Type

Recommendations for New Reliability Standards

RTBPTF believes that operator ability to visualize the status of bulk electric system elements and parameters by means of visualization tools is an essential component of the monitoring process. The Real-Time Tools Survey reveals that entities have used slightly different methodologies and approaches to ensure that they have visualization tools that provide concise, visual monitoring and enhanced multiple views of relevant power system data in real time. Most entities have developed these tools based on their interpretations of operator needs as well as of the implementation of NERC standards.

RTBPTF interprets visualization tools as the user interface layer(s) for the tools/applications necessary to monitor and to maintain the reliability of the bulk electric system. In this report, RTBPTF recommends a mandatory minimum set of monitoring and analysis tools (the Reliability Toolbox; see the Reliability Toolbox Rationale and Recommendation section of this report):

- Alarm tools
- Telemetry data systems
- Network topology processor
- State estimator
- Contingency analysis

Each of these mandatory tools is discussed extensively in its respective sections of the report. Some of the visualization tools discussed in this report are used to present information from one or more of these recommended mandatory applications, which means that these visualization tools must be available. However, RTBPTF believes that it is not necessary for the NERC reliability standards to specify availability standards for these visualization tools in the same context as requiring the availability of the mandatory applications that these visualization tools support. The recommendations within this report focus on mandating the use and availability of the Reliability Toolbox instead of the availability of the user interface (i.e., the corresponding visualization tools.) Requiring the availability of the user interface for the applications is redundant and unnecessary.

Recommendation – S9

Establish a uniform formal process to determine the "wide-area view boundary" and show boundary data/results.

Recommendation – I2

Define wide-area view boundary.

Wide-Area View Boundary

The purpose statement of Standard IRO-003 states "[t]he Reliability Coordinator must have a wide area view of its own Reliability Coordinator Area and that of neighboring Reliability Coordinators." The NERC glossary defines "wide-area" as "[t]he entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits." RTBPTF interprets "wide-area view" as the monitoring boundary for reliability coordinators; it is the RC's view of the "wide area." Several RTBPTF recommendations depend on appropriate definition and exchange of information on bulk electric system elements, which in turn, for RCs, requires greater specificity in the definition of the "wide area." For more detail on the issues of wide-area view, see the Introduction Section.

RTBPTF Recommendation

RTBPTF recommends that NERC establish a uniform, formal process to determine the bounds of the "wide area" and the RC's "wide-area view." The *FERC Staff Assessment* states that "[t]he IRO standards do not specify the criteria for identifying critical facilities whose operating status can affect the reliability of neighboring systems and, therefore, hampers effective [w]ide [a]rea visualization."[21]

RTBPTF agrees with the *FERC Staff assessment* and, therefore, recommends that NERC establish a process to determine the critical flow and status information from adjacent reliability coordinator areas based on detailed system studies to allow the calculation of IROLs, to define what constitutes the bounds of the "wide area." This uniform, formal process would clarify the extent and detail required for the "wide area."

RTBPTF also introduces the concept of a "wide-area view boundary." RTBPTF defines "wide-area view boundary" as the network model boundary for the "wide area." For RCs, the "wide-area view boundary" defines the minimum required network model to support the monitoring requirements for the "wide area." This network model should contain all the bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) bounded by the wide-area view boundary. Sections 4.1, Model Characteristics, and 4.2, Modeling Practices and Tools, further discuss issues related to the "wide-area view boundary."

Once this formal definition process is established by NERC, RTBPTF recommends that a new requirement be established under the current Standard IRO-003 that mandates that each RC apply this formal process to identify its bounds for the its wide-area view. The following requirement is recommended:[22]

PR1. Each reliability coordinator shall identify the bounds of its wide area using the NERC-prescribed uniform formal process (Wide-Area Determination Process). Wide-area visualization tools shall show data/information that encompass the wide area.

RTBPTF recommends the following measure for requirement PR1:

PM1. The reliability coordinator shall demonstrate upon request that it is using the NERC-prescribed uniform formal process (Wide-Area Determination Process) to identify the bounds of its wide area as stated in Requirement PR1. Upon request, the reliability coordinator shall produce documentation describing the process and logs/documents demonstrating application of the process.

Rationale

RTBPTF believes that the wide-area view is analogous to the reliability monitoring boundary for RCs. Therefore, all of the tools and processes for the

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[21] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

[22] Proposed requirements are designated "PR," and proposed measures are designated "PM."

RC to monitor bulk electric system elements and parameters are bounded by the wide area. That is, tools like the state estimator and contingency analysis (and their corresponding power system network models) should be implemented to monitor the RC's wide area. Consequently, network models used by these tools shall cover at a minimum, the wide-area view boundary. A uniform, formal process (Wide-Area Determination Process) eliminates ambiguity for RCs regarding the method of determining the extent of the RC's monitoring boundary (the wide-area view).

Standard IRO-003 mandates that each RC monitor bulk electric system parameters that may have significant impacts upon its RC area and neighboring RC areas. Essentially, each RC is primarily responsible for bulk electric system parameters within its own RC area. However, Standard IRO-003 expands the monitoring requirement to neighboring RC areas based on the wide area.

In Section 1.1, Telemetry Data, RTBPTF recommends that each RC develop and maintain a list of specific bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) within its RC area (the Bulk Electric System Elements List). RTBPTF recommended that the Bulk Electric System Elements List contain the bulk electric system elements within the RC's area necessary for identifying potential or actual SOL or IROL violations within the RC area. Once each RC produces a Bulk Electric System Elements List, RTBPTF believes that this list could be the basis of the uniform, formal process being recommended in proposed requirement PR1 for determining the bounds of the wide area as well as the modeling characteristics for the wide-area view boundary.

If each RC has in its possession its own Bulk Electric System Elements list and is actively monitoring these elements within its own RC area, adjacent RCs could request access to a subset of the elements contained in each adjacent RC's Bulk Electric System Elements Lists. The requesting RC shall use the uniform, formal process to determine extent of the subset of the data it needs. This subset of bulk electric system elements from each adjacent RC's Bulk Electric System Elements List together with the RC's own Bulk Electric System Elements List would then define the bulk electric system elements and parameters for the RC's wide area. Figure 2.2-1 illustrates the concept of the "wide area" as the RC's monitoring boundary.

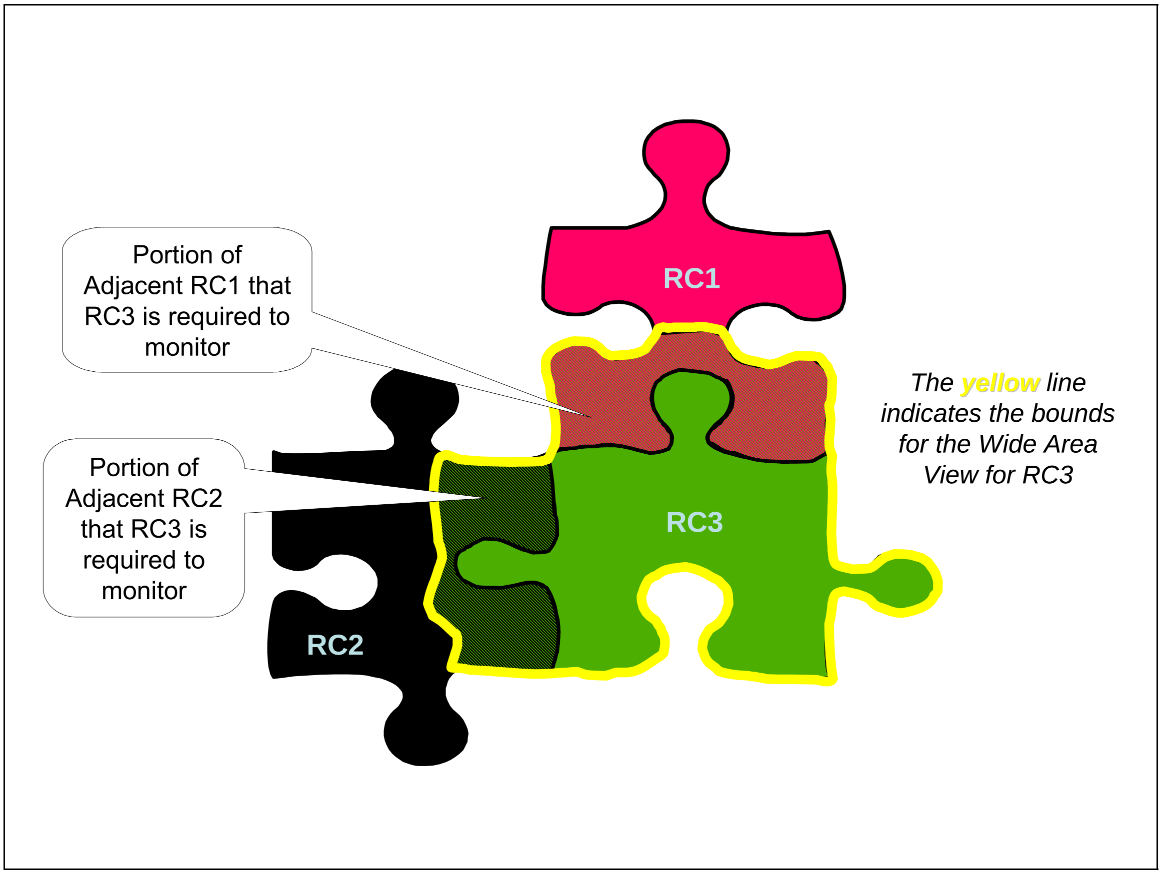

Figure 2.2-1 — Illustration of Wide-Area Concept Related to Monitoring Boundaries for RCs

Usage of Visualization Tools as Measures for Compliance

RTBPTF recommends adding/enhancing measures to require the usage of applicable visualization tools necessary for compliance with existing NERC reliability standards. RTBPTF believes that active demonstration of the usage of visualization tools should be used as measures of compliance with some existing standards. This emphasizes the use of visualization tools to aid reliability entities in “monitoring” bulk electric system elements and parameters.

The existing NERC reliability standards listed below require reliability entities to “monitor” bulk electric system elements and parameters. RTBPTF believes that the word “monitor” does not imply viewing large amounts of raw telemetered or application data. Reliability entities should use visualization tools to concisely organize information as a means to monitor bulk electric system elements and parameters. Visualization tools are highly dependent upon the host application’s data (telemetry or application specific) that are provided to each type of visualization tool.

NERC Reliability Standard IRO-003, Reliability Coordination — Wide Area View

Standard IRO-003 states that the RC must have a wide-area view of its own RC area and that of neighboring RCs. Requirement R1 states, “[e]ach Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary, to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.” Requirement R2 states, “[e]ach Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.”

RTBPTF Recommendation

Standard IRO-003 requires a wide-area view for RCs, but it lacks specificity on the measures. RTBPTF recommends development of measures for the requirements specified by Standard IRO-003. The measures for compliance should include verification, through active demonstration, of the usage of visualization tools by operators to fulfill the requirements of the Standard IRO-003.

Once the bounds of the “wide area” are established, each RC shall be required to demonstrate the use of adequate visualization tools and/or summary displays (as appropriate) to comply with the “wide-area view” standard, as mandated by Standard IRO-003. Each RC shall demonstrate, at a minimum, the existence and usage of specific set of visualization tools and/or summary displays (as appropriate) corresponding for each requirement per Standard IRO-003 (see Table 2.2-25 below). As shown in Table 2.2-25, RTBPTF recommends a measure for each requirement in Standard IRO-003.

Standard IRO-003 Requirement[23]	Recommended Measures
R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	RTBPTF recommends that the following measure for Requirement R1.[24] PM1. Each reliability coordinator shall demonstrate the active use of visualization tools and summary displays listed below to comply with Requirement R1. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area. a. Contingency Analysis Summary Displays b. Dynamic Overview Displays or Dynamic Mapboard c. Wide-Area Visualization Tools <u>Rationale:</u> RTBPTF interprets the determination of "any potential System Operating Limit and Interconnection Reliability Operating Limit violations" as the output solution of the contingency analysis application. RTBPTF recommends contingency analysis as a mandatory tool for reliability coordinators. At a minimum, Requirement R1 requires the demonstration and usage of the contingency analysis application and its related summary displays and output solution. Section 2.6 of this report, Contingency Analysis, discusses the recommendations for the contingency analysis application. Requirement R1 also implies the demonstration and usage of the following list of visualization tools[25] and summary displays for bulk electric system elements within the reliability coordinator's wide area. a. Contingency Analysis Summary Displays b. Dynamic Overview Displays or Dynamic Mapboard c. Wide Area Visualization Tools The Real-Time Tools Survey indicates prevalent practice concerning dynamic overview displays (100%), dynamic mapboard (67%), and wide-area visualization tools (88%) among reliability coordinators. RTBPTF believes that mandating that RCs use wide-area visualization tools <u>and</u> either dynamic overview displays or a dynamic mapboard gives RCs the situational awareness capability mandated by Requirement R1. The scope of the use of these visualization tools is strongly noted by RTBPTF to <u>encompass</u> the RC's wide area. It is not sufficient just to show the RC area.

[23] Each requirement here is stated verbatim from the current Standard IRO-003.
[24] The numbering scheme for these proposed measures (PM) coincides with the existing requirements – e.g., the proposed measure for Requirement R1 is numbered PM1.
[25] The definitions of each type of visualization tool are discussed in the Summary of Findings section above.

Standard IRO-003 Requirement[23]	Recommended Measures
R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	RTBPTF recommends that the following measure for Requirement R2. PM2. Each reliability coordinator shall demonstrate the active use of contingency analysis summary displays to comply with Requirement R2. These summary displays shall show information within the reliability coordinator's wide area. <u>Rationale:</u> RTBPTF interprets the knowledge of "current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation" as the output solution of the contingency analysis application. At a minimum, this requires demonstration and usage of the contingency analysis application and its related displays and output solution. Section 2.6 of this report, Contingency Analysis, discusses the recommendations for the contingency analysis application. The second part of this requirement ("status of any facilities that may be required to assist area restoration objectives") is discussed in Section 3.7, Blackstart Capability, of this report.

Table 2.2-25 — Recommended Measures for Standard IRO-003

NERC Reliability Standard IRO-002, Reliability Coordination — Facilities

Standard IRO-002 states that RCs need information, tools, and other capabilities to perform their responsibilities. Requirement R7 of the standard requires that each RC have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.

Recommendation – S10

Develop compliance measures for verification of the usage of "wide-area overview display" visualization tools.

RTBPTF Recommendation

Standard IRO-002 is specific in requiring RCs to have "wide-area overview displays," but it lacks specificity regarding measures. RTBPTF recommends the development of a measure for the requirements specified in Standard IRO-002 (Requirement R7). The measure for compliance includes verification, through the active demonstration of the usage of visualization tools by the RC to fulfill the "wide-area overview display" requirement of the standard mentioned above. RTBPTF recommends the following measure for Requirement R7:[26]

[26] The numbering scheme for these proposed measures (PM) coincides with the existing requirements – e.g., the proposed measure for Requirement R7 is numbered PM7. Also,

PM7. Each reliability coordinator shall demonstrate the active use of visualization tools and summary displays listed below to comply with Requirement R7. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area.

a. Dynamic Overview Displays or Dynamic Mapboard
b. Wide Area Visualization Tools

Rationale

The rationale for this measure is the same as for Requirement R1 of Standard IRO-003. This recommended measure makes clear how to comply with the "wide-area view overview display" Requirement R7.

NERC Reliability Standard IRO-005 — Reliability Coordination — Current Day Operations

The standard's purpose states, "the Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas."

Requirement R1 states that each reliability coordinator shall monitor its reliability coordinator area parameters. The subrequirements are listed below verbatim from Standard IRO-005 (Requirement R1):

R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.
R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
R1.4. System real and reactive reserves (actual versus required).
R1.5. Capacity and energy adequacy conditions.
R1.6. Current ACE for all its Balancing Authorities.
R1.7. Current local or Transmission Loading Relief procedures in effect.
R1.8. Planned generation dispatches.
R1.9. Planned transmission or generation outages.
R1.10. Contingency events.

Requirement R7 is also discussed in other sections (for mandatory tools) with additional measures recommended by RTBPTF.

RTBPTF Recommendation

RTBPTF recommends that each RC demonstrate the use of adequate visualization tools and/or summary displays (as appropriate) to fulfill the monitoring requirements for each of the items listed in Requirement R1 of Standard IRO-005. Each RC shall demonstrate easily accessible visualization tools and/or summary displays (as appropriate) that show the appropriate information as specified by each sub-requirement under Requirement R1. Note that this is in addition to the measures recommended in Section 1.1, Telemetry Data.

RTBPTF recommends addition of measures based on demonstrated usage of visualization tools and/or summary displays (as appropriate) to provide clarity for reliability coordinators regarding how to comply with Standard IRO-005 (Requirement 1). As shown in Table 2.2-26, most of the sub-requirements give the reliability coordinator the flexibility of either demonstrating the active use of summary displays (as appropriate) based on data from other applications/tools or demonstrating the active use of the specified visualization tool(s) for a particular sub-requirement. Requirement R1.1 is the only sub-requirement that mandates that the RC demonstrate use of specific types of visualization tools. In most cases, summary displays are appropriate to fulfill the other sub-requirements (i.e., Requirement 1.2-Requirement 1.7 and Requirement 1.10).

Standard IRO-003, Requirement R1 Sub-requirements	Recommended Measures
R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.	RTBPTF recommends the following measure for Requirement R1.1:[27] PM1.1. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.1. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area. a. Dynamic Overview Displays or Dynamic Mapboard b. Wide-Area Visualization Tools c. Remedial Action Scheme Monitor or Automatic Safety Net <u>Rationale:</u> Note that recommended measures regarding the monitoring requirement for the "current status of Bulk Electric System elements" as mandated by Requirement R1.1 are also thoroughly discussed in Section 1.1, Telemetry Data. The Real-Time Tools Survey indicates that, among RCs, dynamic overview displays are widely used (100%), as are dynamic mapboard (67%), and wide-area visualization tools (88%). RTBPTF believes that mandating that RCs use wide-area visualization tools <u>and</u> either dynamic overview displays or dynamic mapboards will give RCs the situational awareness capability mandated by Requirement R1.1 to monitor "current status of Bulk Electric System elements." For example, a display containing the all the RC area generating units with their corresponding AVR status could demonstrate usage of wide-area visualization tools. RTBPTF also believes that Requirement R.1.1 mandates that RCs have situational awareness of the status of SPSs. RTBPTF interprets this mandate to mean that RCs must use either a RAS monitor or automatic safety net visualization tools. The Real-Time Tools Survey indicates that RAS monitors are commonly used (88%), and automatic safety nets are not (27%). RTBPTF believes demonstrated use of either of the two tools could be used to demonstrate active usage of visualization tools for situational awareness of RASs.

[27] The numbering scheme for these proposed measures (PM) coincides with the existing requirements – e.g., the proposed measure for Requirement R1.1 is numbered PM1.1.

Standard IRO-003, Requirement R1 Sub-requirements		Recommended Measures
R1.2.	Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	RTBPTF recommends the following measure for Requirement R1.2: PM1.2. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.2. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area. a. State estimator solution summary displays or contingency analysis summary displays b. Wide-area visualization tools containing the state estimator solution or the base-case solution of the contingency analysis application <u>Rationale:</u> RTBPTF interprets "current pre-contingency element conditions" as the state estimator solution or the base-case solution of the contingency analysis application. Section 2.5 of this report, State Estimator, discusses the recommendations for the state estimator application. Section 2.6 of this report, Contingency Analysis, discusses the recommendations for the contingency analysis application. In addition, RTBPTF recommends that the RC be required to demonstrate the active use of wide-area visualization tools containing the state estimator solution or the base-case solution of the contingency analysis application. Wide-area visualization tools would aid RCs in focusing on important parameters/elements based on the state estimator solution or the base-case solution of the contingency analysis application.
R1.3.	Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	RTBPTF recommends the following measure for Requirement R1.3: PM1.3. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.3. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area. a. Contingency analysis summary displays b. Wide-area visualization tools containing output solution of the contingency analysis application <u>Rationale:</u> RTBPTF interprets "current post-contingency element conditions" as the output solution of the contingency analysis application. Section 2.6 of this report, Contingency Analysis, discusses the recommendations for the contingency analysis application. In addition, RTBPTF recommends that the RC be required to demonstrate the active use of wide-area visualization tools containing the output solution of the contingency analysis application. Wide-area visualization tools would aid RCs in focusing on important parameters/elements based on the output solution of the contingency analysis application.

Standard IRO-003, Requirement R1 Sub-requirements	Recommended Measures
R1.4. System real and reactive reserves (actual versus required)	RTBPTF recommends the following measure for Requirement R1.4: PM1.4. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.4. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area. a. Wide-area visualization tools containing output of operating reserve calculations b. Reactive reserve monitor or wide-area visualization tools containing output of reactive reserve calculations <u>Rationale:</u> The "real reserves" are covered by the balancing resources and demand standards and termed "operating reserves." RTBPTF recommends that RCs be required to demonstrate the active use of wide-area visualization tools or summary displays (as appropriate) based on the output of operating reserve calculations in order to comply with the "monitoring" requirements of Requirement R1.4. Section 3.1, Reserve Monitoring, discusses recommendations for reserve monitoring. RTBPTF interprets "reactive reserves (actual versus required)" as the output of the reactive reserve monitor visualization tool for monitoring the status of reactive resources. This visualization tool monitors reactive resources (dynamic and/or static) to determine whether they are sufficient based on current conditions. It has the ability to alarm the operator when either a unit in the area has reached its reactive capability or there are insufficient reactive resources (dynamic and/or static) for an area. RTBPTF recommends that the RC be required to demonstrate the active use of the reactive reserve monitor visualization tool or an equivalent wide-area visualization tool or summary displays (as appropriate) based on the output of reactive reserve calculation as discussed in Section 3.1, Reserve Monitoring.

Standard IRO-003, Requirement R1 Sub-requirements		Recommended Measures
R1.5.	Capacity and energy adequacy conditions	RTBPTF recommends the following measure for Requirement R1.5: PM1.5. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.5. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area. a. Capacity assessment application summary displays or wide-area visualization tools containing output of the capacity assessment application. <u>Rationale:</u> RTBPTF interprets "capacity and energy adequacy conditions" as the output of the capacity assessment application. This application gives an overview of available generation capacity (MW or Mvar) in real-time. Section 2.12 of this report, Capacity Assessment, discusses recommendations for the capacity assessment application. RTBPTF recommends that RCs be required to demonstrate the active use of the capacity assessment application (with its corresponding summary displays) or an equivalent wide-area visualization tool that shows capacity and energy adequacy conditions.
R1.6.	Current ACE for all Balancing Authorities	RTBPTF recommends the following measure for Requirement R1.6: a. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.6. The visualization tools or summary displays shall contain the current ACE for all balancing authorities within the reliability coordinator area. <u>Rationale:</u> The current ACE for all of the RC's BAs is obtainable as ICCP-specific data. Compliance may be demonstrated by each RC showing the monitoring (through ICCP data exchange or direct telemetry methods) of the current ACE for all its BAs. Current ACE data are also required per Standard TOP-005. In addition, RTBPTF recommends that the RC be required to demonstrate the active usage of equivalent wide-area visualization tools or summary displays (as appropriate) that show ACE data of balancing authorities within the RC area.
R1.7.	Current local or Transmission Loading Relief procedures in effect	RTBPTF is not recommending any measures requiring any visualization tool for Requirement R1.7. Section 2.14 of this report, Other Tools (Current and Operational), discusses the congestion management application, inter-regional real-time coordination for congestion management application, and inter-regional real-time coordination for market redispatch application.
R1.8.	Planned generation dispatches	Not within the scope of RTBPTF
R1.9.	Planned transmission or generation outages	Not within the scope of RTBPTF

Standard IRO-003, Requirement R1 Sub-requirements	Recommended Measures
R1.10. Contingency events	Requirement R1.1 addresses the continual monitoring of bulk electric system whereas Requirement R1.10 addresses event monitoring. When a critical facility (considered a contingent element) is unavailable, this may be a result of multiple bulk electric system elements indicating a change in status. For example, when a 230-kV transmission line is unavailable (a contingency event), this may be a result of transmission circuit breakers showing a status open. RTBPTF interprets the monitoring of "contingency events" as the output of alarm tools. RTBPTF is not recommending any measures related to visualization tools usage for Requirement R1.10. Section 2.1, Alarm Tools, discusses recommendations for alarm tools.

Table 2.2-26 — Recommended Measures for IRO-005, Requirement 1

NERC Reliability Standard TOP-006 — Monitoring System Conditions

Standard TOP-006 exists, "[t]o ensure critical reliability parameters are monitored in real-time." Requirement R2 states, "[e]ach Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources."

RTBPTF Recommendation

The requirement to use visualization tools is not limited to RCs but also applies to other reliability entities. In fact, the *Outage Task Force Final Blackout Report* attributes the lack of situational awareness by TOP FE's operators to the lack of an effective alternative to easily visualize the overall conditions once FE's alarm tools failed. An alternative means to readily visualizing overall system conditions, including the status of critical facilities, would have enabled FE operators to become aware of forced transmission-line outages in a timely manner even though the alarms were non-functional.

RTBPTF recommends the following measure for Standard TOP-006 (Requirement R2):[28]

PM2. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate, at a minimum, the existence and usage of the following set of visualization tools and/or displays as a measure for compliance with Standard TOP-006 (Requirement 2):
  - a. Dynamic overview displays or dynamic mapboard
  - b. Reactive reserve monitor
  - c. Remedial action scheme monitor or automatic safety net

[28] The numbering scheme for these proposed measures (PM) coincides with the existing requirements – e.g., the proposed measure for Requirement R2 is numbered PM2.

Rationale

The rationale for Standard TOP-006, Requirement R2 is the same as for Standard IRO-003, Requirement R1 above. This is essentially the same requirement extended to TOPs and BAs.

Recommendation – G2

Consider human factors, ergonomics and maintenance/support issues in implementing visualization tools.

Recommendations for New Operating Guidelines

The implementation of different types of visualization tools would most likely be a customized effort by each entity, so a general operating guideline for each type of visualization tool would be of little or no value. Therefore, RTBPTF is not recommending any operating guidelines specifying which type of visualization tools to use/implement. However, numerous existing research studies/reports in the area of visualization and user interface could be used by entities in designing and implementing their visualization tools. Issues to consider in implementing visualization tools include, but are not limited to, the following:

- Human factors, ergonomics
- Industry adoption of standardized or common presentation of data
- Technical innovations in visualization tools
- Maintenance/support issues

Features of Wide-Area Visualization Tools

In the area of wide-area visualization tools, the Real-Time Tools Survey provides insight regarding desired features of certain industry implementations. These features are worthy of consideration by entities implementing wide-area visualization tools. Functional features to consider in implementing wide-area visualization tools include, but are not limited to, the following:

- Capability to render information using conventional graphing techniques (e.g., pie charts, flashing lines, etc), as well as rendering information using more advanced techniques (e.g., contouring of voltage data, reliability hotspots, etc.)
- Capability to link wide-area visualization tools to alarm tools.
- Capability to mix data from different sources (e.g., telemetry system data with state estimator solution data)
- Capability to present electric system data either geographically or through a schematic representation

- Capability to automatically create a visual representation of the entity's network model; i.e., the wide-area visualization tool is driven by the network model.

Recommendation – A4

Conduct research to assess current technology and practices related to the use and application of visualization tools

Areas Requiring Further Analysis

RTBPTF recommends that NERC, with the help of other research (or government) entities, continue to assess current technology and practices related to the use and application of visualization tools. RTBPTF also notes that Recommendation 13 of the *Outage Task Force Final Blackout Report* states, "DOE should expand its research programs on reliability-related tools and technologies. More investment in research is needed to improve grid reliability, with particular attention to improving the capabilities and tools for system monitoring and management." Items to be included in this research related to visualization tools are:

- Development of practical real-time applications for wide-area system monitoring using phasor measurements and other synchronized measuring devices, including post-disturbance applications
- Development and use of enhanced techniques for modeling and simulation of contingencies, blackouts, and other grid-related disturbances
- Development of practical human factors guidelines for power system control centers

To reiterate, the *Outage Task Force Final Blackout Report* listed the following recommendations from previous investigations concerning visualization tools[29]:

- In the control center, use a dynamic line loading and outage display board to provide operating personnel with rapid and comprehensive information about the facilities available and the operating condition of each facility in service.
- Give control centers the capability to display to system operators computer-generated alternative actions specific to the immediate situation, together with expected results of each action.

[29] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 108.

Recommendation – A5

Establish a Visualization Tools Working Group (VTWG) to foster and facilitate sharing of best practices.

RTBPTF also recommends the following for NERC's consideration:

- Establish a Visualization Tools Working Group (VTWG) to foster and facilitate sharing of best practices within the industry for the use of visualization tools. This working group could continue to recommend and develop standards and operating guidelines in the area of best methods and practices in presenting information to operators.
- Establish industry and technical forums that involve academic, research organizations, and other organizations to aid and guide the industry in the area of visualization tools.

Examples of Excellence

With visualization tools, the following entities have taken slightly different approaches to ensure that they have user interfaces that provide concise, visual monitoring and enhanced multiple views of relevant power system data in real time. These visualization tools are available to operators to help them monitor and better understand system events and/or conditions across power systems that may be affecting reliable operation in their part of the power system. Visualization tools are provided to the operators to maintain or enhance their situational awareness.

RTBPTF cites the implementation of the facilitated transaction checkout (FTC) tool by all balancing authorities within the Northeast Power Coordinating Council as an example of excellence (See EOE-4 in Appendix E). FTC is a message structure that enables neighboring reliability entities to query each other's interchange transaction stack and perform an automated comparison prior to performing verbal checkout, thus improving the accuracy associated with transaction checkout.

RTBPTF cites the implementation of PowerWorld Retriever by Southwest Power Pool to provide a system overview (i.e., voltage contouring), as well as alarms using pie charts and flashing lines, as an example of excellence (See EOE-5 in Appendix E).

RTBPTF cites the implementation of an expansive wide-area overview display with underlying BA and one-line displays, including flowgate and reactive monitoring displays, by MISO as an example of excellence (See EOE-6 in Appendix E).

RTBPTF cites American Transmission Company’s use of an application that interfaces directly with its EMS to provide system operators with a dynamic wide-area overview of its network topology as well as state estimation of the neighboring systems as an example of excellence (See EOE-7 in Appendix E).

Section 2.3
Network Topology Processor

Definition

The network topology processor (NTP) is a SCADA-based application that determines facility status and station configuration based on breaker and switch status data. The processor converts a nodal network model into a bus-branch model, for use by other applications such as the state estimator. It may perform the same function for study network applications such as power flow.

Background

Software tools such as the network NTP, state estimator, and contingency analysis allow RCs and TOPs to maintain current information about the condition of their bulk electric system facilities and to monitor the impacts on those facilities of events in neighboring systems.

The electricity system behaves quite dynamically during the course of a day. NTP tracks changes in system configuration using algorithms that regularly analyze phenomena such as changing breaker and switch status. The result is an accurate model of the current system configuration and preparation of data needed for other situational awareness tools. NTP configuration models are vital to downstream applications such as state estimators.

RTBPTF agrees with a recommendation made at the July, 2004 FERC Technical Conference[30] that NTP use be a minimum requirement for reliability entities. The task force also fully supports the *Outage Task Force Final Blackout Report* observation that the state estimator require a "… model of the power system that reflects the configuration of the network (i.e. which facilities are in service and which facilities are not)..."[31] This conclusion effectively mandates NTP usage.

The constant evaluation of electrical connectivity is essential to provide input to the state estimator (and other near-real-time network applications). Consequently, the NTP must be highly available and its analyses highly accurate for reliability entities to effectively monitor bulk electric system conditions. As a result of the blackout investigation findings, NERC issued directives to FE, MISO, and Pennsylvania-New Jersey-Maryland Interconnection (PJM), including a mandate that FE ensure that its state estimator and contingency analysis functions "execute reliably full contingency analyses automatically every ten

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[30] Macedo, Frank. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14.
[31] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 47.

minutes or on demand, etc." NERC also required MISO to fully implement and test its NTP to provide operating personnel a real-time view of system status for "all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems." Entities were also required "to establish a means of exchanging outage information" within their footprints and with neighboring systems to ensure that each state estimator "has accurate and timely information to perform as designed."[32]

The purpose of the NTP section of the Real-Time Tools Survey was to obtain a snapshot of current NTP usage throughout the industry. Special emphasis was placed on determining reliability entities' practices for viewing and monitoring bulk electric system elements as well as maintenance and support practices related to NTP. Results summarized below emphasize responses from RCs and TOPs because limited response was received from BAs.

See Section 2.4, Topology and Analog Error Detection, for a discussion of enhanced topology error detection.

Summary of Findings

Key survey results from the NTP section are that NTPs are operational at many RCs and TOPs, required to develop topology models for the state estimator and contingency analysis applications, used to independently detect isolated and/or disconnected equipment, used to support other situational awareness tools (i.e., dynamic mapboards), executed frequently and quickly, and monitored to ensure high availability.

RTBPTF recommends additions to/modifications of certain NERC reliability standards to ensure NTP availability, performance, and accuracy. The task force recommends that compliance measures be appropriately coordinated with the alarm tools and/or state estimator applications.

Survey results suggest that NTP is commonly used throughout the industry, primarily by system operators and control room personnel. The survey found that NTP algorithms execute rapidly and on a regular or frequent basis.

Considering these findings and the necessity for developing accurate connectivity models reflecting real-time system conditions, the task force classifies NTP as a critical real-time tool.[33]

A significant number of RCs and TOPs responded to the survey questions regarding NTP, and responses from these two groups were fairly consistent.

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[32] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 152.
[33] The concept of a "critical real-time tool" is explained in Section 5.4, Critical Applications Monitoring.

Other groups responded in statistically insignificant numbers; therefore, most of the discussion in this section is limited to RC and TOP responses.

Characteristics of Network Topology Processors

The survey results confirm that NTPs are widely used and operational throughout the industry, as shown in Table 2.3-1. Ninety-four percent of RCs (16 out of 17) and 67 percent of TOPs (18 out of 27) who responded to the survey report that they have NTPs. In addition, almost all RCs (16 out of 16) and TOPs (17 out of 18) that have this application indicate that it is operational. Two TOPs plan to add NTPs in the future, and 1 RC and 7 TOPs do not plan to add NTPs.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, "32/38=84%" means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

NTP Characteristics	All	RCs
Do you have Network Topology Processor?	35/47=74%	16/17=94%
Is your NTP operational?	34/35=97%	16/16=100%
Is your NTP Off-the-Shelf with some Customization?	11/34=32%	7/16=44%
Is your NTP Off-the-Shelf?	17/34=50%	6/16=38%
Is your NTP Supplied By SCADA/EMS Vendor?	30/34=88%	14/16=88%
Is your NTP Fully Integrated With Production SCADA/EMS?	32/34=94%	14/16=88%

Table 2.3-1 — NTP Characteristics

Users overwhelmingly employ "off-the-shelf" or "off-the-shelf with some customization" NTP packages (81 percent of RCs, 13 out of 16, and 88 percent of TOPs, 15 out of 17), which suggests that vendor packages with satisfactory NTP functionality are available. NTP packages are typically fully integrated with users' EMS systems. However, some respondents use third-party or in-house products. One RC's NTP is interfaced to the SCADA/EMS, and another RC's NTP is a stand-alone product. Nearly 90 percent of RCs' (14 out of 16) and TOPs' (15 out of 17) NTPs were provided by their SCADA/EMS vendors. Two RCs and no TOPs obtained their NTPs from a third-party vendor. Two TOPs and no RCs developed their NTPs in house.

Respondents with functioning NTP applications report overwhelmingly [94 percent of RCs (15 out of 16) and 94 percent of TOPs (15 out of 16)] that their NTPs use a topology algorithm rather than a Boolean or other type of approach. Most of the 33 RCs and TOPs responding to the NTP questions report that their NTPs are interfaced for use by the state estimator and power-flow applications. High percentages (about two-thirds or more) of both RCs and TOPs interface their NTPs to SCADA and contingency analysis applications. Other functions are also interfaced but to a lesser degree. See Table 2.3-2. Several entities took the time to comment that their NTPs are also interfaced to an outage-scheduling system, which suggests that this interface, not specifically itemized in the survey question, may be relatively common as well.

NTP Application Interfaces	All	RCs
SCADA	26/34=76%	11/16=69%
Alarm Tools	14/34=41%	8/16=50%
Monitoring and Visualization Tools	16/34=47%	10/16=63%
Topology Error Detection	15/34=44%	10/16=63%
State Estimator	32/34=94%	16/16=100%
Contingency Analysis	26/34=76%	14/16=88%
Critical Facility Loading Assessment	4/34=12%	2/16=13%
Power Flow	29/34=85%	14/16=88%
Study Real-Time Maintenance	10/34=29%	6/16=38%
Other(s)	3/34=9%	2/16=13%

Table 2.3-2 — NTP Application Interfaces

Seventy-nine percent of respondents (12 RCs and 14 TOPs) report that they need to manually update non-telemetered internal facility status points. This suggests that even though a majority of respondents interface their SCADA systems with the NTP, many must manually maintain status information in some locations to support all equipment in their models. At least two-thirds of RCs (12 out of 16) and TOPs (11 out of 17) indicate that they must perform manual updates of external facility status points. If these status points are not kept current, their "wide-area view"[34] of the bulk power system could be affected.

NTP Users

The majority of respondents, i.e., 94 percent of RCs (15 out of 16) and 82 percent of TOPs (14 out of 17), indicate that operators and other control room staff are the primary users of NTP, suggesting that the application is primarily a situational awareness tool for operators. Although others use it, the percentages are much smaller, as Table 2.3-3 shows.

[34] "Wide-area view" is a term introduced by Standard IRO-003.

Users	Who are primary Users?		Who are secondary Users?	
	All	RCs	All	RCs
System Operators and/or Other Control Room Staff	30/34=88%	15/16=94%	3/29=10%	1/15=7%
Operations Support Staff	16/34=47%	8/16=50%	13/29=45%	7/15=47%
EMS and/or information technology (IT) Support Staff	9/34=26%	4/16=25%	16/29=55%	7/15=47%
Supervisory and/or Management Staff	5/34=15%	1/16=6%	8/29=28%	3/15=20%
Other(s)	0/34=0%	0/16=0%	4/29=14%	3/15=20%
Not Used On a Continuous Basis (7 x 24 x 365)	0/34=0%	0/16=0%	1/29=3%	0/15=0%

Table 2.3-3 — Who uses NTP?

Features and Functions

All 33 RCs and TOPs rank NTP as “essential” or “desirable,” which makes clear the importance of this application. The survey responses shown in Table 2.3-4, as well as the respondents’ comments cited at the end of this paragraph, illustrate the variety of roles that this application plays.

NTP Functions and Features	All	RCs
Identify electrical islands & equipment in each island	31/34=91%	15/16=94%
Island detection is Essential	15/29=52%	8/14=57%
Island detection is Desirable	13/29=45%	5/14=36%
Identify equipment that is open-ended at one terminal	29/32=91%	14/15=93%
Open-ended equipment detection is Essential	14/27=52%	8/12=67%
Open-ended equipment detection is Desirable	12/27=44%	4/12=33%
Identify equipment that is completely de-energized	27/31=87%	12/14=86%
De-energized equipment detection is Essential	12/26=46%	7/12=58%
De-energized equipment detection is Desirable	12/26=46%	4/12=33%
Individually override any status in NTP, including taps	27/31=87%	13/14=93%
Override of individual status points is Essential	23/27=85%	12/13=92%
Override of individual status points is Desirable	4/27=15%	1/13=8%
Override a large number of statuses from saved case	8/31=26%	6/14=43%
Override of status pts. from saved case is Essential	3/5=60%	3/5=60%
Override of status pts. from saved case is Desirable	2/5=40%	2/5=40%
Detect and identify abnormal split buses	13/30=43%	6/14=43%
Abnormal split bus detection is Essential	6/13=46%	3/6=50%
Abnormal split bus detection is Desirable	7/13=54%	3/6=50%
Detect & identify abnormal breaker & switch statuses	25/30=83%	10/14=71%
Abnormal breaker/switch status detection is Essential	13/20=65%	3/ 7=43%
Abnormal breaker/switch status detection is Desirable	6/20=30%	4/ 7=57%
Define different voltage limits at each node	13/30=43%	8/14=57%
Different voltage limits at each node is Essential	8/12=67%	4/ 7=57%
Different voltage limits at each node is Desirable	4/12=33%	3/ 7=43%
Chronologically view all facility outages & returns	16/30=53%	9/14=64%
Chronological view of outages/returns is Essential	13/15=87%	9/9=100%
Chronological view of outages/returns is Desirable	2/15=13%	0/9=0%

Table 2.3-4 — NTP Functions and Features

NTP's roles include: preparing models for the state estimator/contingency analysis, identifying equipment outages, identifying de-energized equipment, identifying the existence of multiple network islands, and driving dynamic mapboards.[35] The number of respondents that have the features discussed in this paragraph suggests that these features are common and readily available.

[35] See Section 2.2, Visualization Tools, for a discussion of the application and prevalence of dynamic mapboards.

Most respondents [94 percent of RCs (15 out of 16) and 88 percent of TOPs (15 out of 17)] indicate that their NTPs can detect two or more electrical islands, and 93 percent of RCs (13 out of 14) and all TOPs (14 out of 14) rank this feature as "essential" or "desirable." About one-half of RCs (8 out of 14) and TOPs (6 out of 14) can specify the minimum number of buses in a valid electrical island. Respondents can identify up to a minimum of 10 electrical islands; the maximum number of islands that can be identified is essentially unbounded (9,999). One RC and 2 TOPs that do not have the island detection function indicate that it would be "desirable." Detection of open-ended or de-energized equipment is also a common feature. Very high percentages of respondents [93 percent of RCs (14 out of 15) and 88 percent of TOPs (14 out of 16)] report that their NTP applications can detect open-ended equipment at one terminal, and 86 percent of RCs (12 out of 14) and 88 percent of TOPs (14 out of 16) can detect de-energized equipment. Users overwhelmingly (more than 90 percent) rate these features as "essential" or "desirable."

The respondent's comments below suggest the importance and variety of NTP implementations:

> "There is topology processing that is integrated into the State Estimator and the other network applications. We also have a SCADA topology processor that runs as part of the SCADA environment to indicate de-energized equipment based solely on SCADA information."
>
> "Topology outputs are used for mapboard indication and line, transformer, and outage alarming."
>
> "Provides bus/branch model for State Estimator and other network applications. Provides current and chronological history of facility status. Detects network islanding."
>
> "Local and wide area situation awareness would be very difficult to achieve, if at all, without network topology. One could not, generally speaking, achieve good contingency analysis results without NTP."

Additional survey questions reveal other, less common uses of NTP. For example, 43 percent of RCs (6 out of 14) and 40 percent of TOPs (6 out of 15) use NTP to detect abnormal split buses. All of the RCs (6 out of 6) and TOPs (6 out of 6) that have abnormal split bus detection rank this feature "desirable" or "essential," with RCs rating the function as essential more frequently than TOPs. Seventy-one percent of RCs (10 out of 14) and 93 percent of TOPs (14 out of 15) can also detect abnormal breaker and switch status. However, this feature is not used by all who have it. Most RCs (7 out of 7) and TOPs (11 out of 12) that have and use this feature consider it "essential" or "desirable." In contrast to many other NTP-related features and functions, TOPs (9 out of 12) rank this feature "essential" more often than did RCs (3 out of 7), suggesting that TOPs that have the feature consider it to be important. It should be noted that every one of the RCs (4 out of 4) that reported that they did not have the feature indicate that it would be “desirable.”

Performance, Monitoring, and Availability

Several survey questions attempted to quantify NTP performance, which could be useful information for establishing norms. The results indicate that the NTP function requires minimal execution time and is generally set to run automatically and fairly frequently. When asked how their NTP is normally triggered to run in real time, all RCs (16 out of 16) and all TOPs (17 out of 17) report that their NTPs were triggered to run automatically.

Users report a fairly wide range of cycle times - from a low of two seconds to a high of 1,800 seconds - with an average of just under 300 seconds (five minutes). For most, the function executes rapidly. The 16 RCs and 17 TOPs report times averaging well under 10 seconds, and many respondents (11 out of 16 RCs and 12 out of 17 TOPs) report times of five seconds or less. Seven RCs and TOPs require as little as one second to execute the application, and no one reports an execution time that exceeds 30 seconds.

In addition to addressing execution speed and frequency, the survey addressed availability and monitoring. This information is of interest to the task force for establishing reasonable recommendations for standards and compliance measures. Companies were asked to report multiple monitoring tools if applicable. Eighty percent of RCs (8 out of 10) and 80 percent of TOPs (8 out of 10) report that the most common method of monitoring NTP availability is a “watchdog.” Other techniques include 1 RC using a redundant system comparison and 5 RCs and TOPs using alarm displays, flag and system messages, operator monitoring, and system health checks to ensure availability. Of those reporting, 7 out of 10 RCs and 6 out of 10 TOPs indicate that alarm tools show NTP status to support personnel; 50 percent of RCs (5 out of10) use continuous displays for this purpose. Paging systems, web-based or special application displays, and email and phone calls are also employed but by less than 50 percent of any reporting group. Two-thirds of the RCs and TOPs responding (12 out of 18) indicate that failed status is detected and reported within 300 seconds or less. Responses from 10 RCs and 8 TOPs indicate that failed status is detected and reported in time frames ranging from a minimum of one second to a maximum of 1,560 seconds (26 minutes).

Frequency of Regular Manual Health Checks for the Entity's NTP	All	RCs
Weekly	1/21=5%	0/12=0%
Daily	4/21=19%	3/12=25%
Hourly	1/21=5%	1/12=8%
As Needed	12/21=57%	5/12=42%
Other(s)	3/21=14%	3/12=25%

Table 2.3-5 — NTP Manual Health Checks

Table 2.3-5 summarizes the responses regarding how often a regular manual NTP health check is performed. Twenty-one respondents answered this survey question. Overall, 42 percent (5 out of 12) of RCs and 57 percent (12 out of 21) TOPs that responded to this survey question report that regular, manual health checks are performed on an as-needed basis to ensure that the NTP application is running successfully. The remaining respondents report that their NTP health checks are performed continuously with different periodicities as indicated in the table.

NTP Monitor and Metrics	All	RCs
Does your NTP have the ability to detect and independently notify operators and support staff that the NTP is down or functioning incorrectly?	20/30=67%	10/14=71%
Do you use a Watchdog to detect NTP failures?	16/20=80%	8/10=80%
Is the status of NTP monitored continuously (24x7x365)?	21/21=100%	12/12=100%
Do operators attempt to resolve problems prior to notifying support?	8/21=38%	5/12=42%
Are your support personnel available continuously (24x7x365)?	18/21=86%	11/12=92%
Do you have historical NTP solution rate data and/or metrics?	8/31=26%	6/15=40%

Table 2.3-6 — NTP Monitor and Metrics

Overall, only 26 percent of respondents (6 out of 15 RCs and 2 out of 15 TOPs) have solution availability metrics to describe how often NTP solves for a given number of runs (see Table 2.3-6). Although this is a statistically small group, 100 percent of those that have metrics (6 out of 6 RCs and 2 out of 2 TOPs) use them, and most (5 out of 6 RCs and 2 out of 2 TOPs) rate them “desirable” or “essential” for situational awareness. Sixty percent of respondents without metrics (including 7 out of 9 RCs and 7 of 13 TOPs) indicate that metrics would have minimal value. Two-thirds of RCs (4 out of 6) and half of the TOPs (1 out of 2) with metrics generate their statistics automatically. No respondents generate them manually. However, 1 respondent’s metrics are based on the number of solutions obtained while another respondent runs scripts each day to derive the metrics.

See the “Support” subsection below for further discussion.

Questions regarding the periodicity of metrics and the period of unavailability that respondents consider will have significant impact on their system operations elicited only a small number of responses (6 total). Therefore, RTBPTF can draw no conclusions on these issues. It is of interest that availability statistics appear to be based on estimated rather than calculated values. In addition, although only a limited number of respondents address the leading causes of NTP unavailability, the two causes cited are bad telemetry (with good quality codes) and data link/lost telemetry (at least 1 respondent reports that more than 50 percent of problems resulted from these two causes).

Enhanced Functionality

Of those responding to questions about NTP enhanced functionality, most RCs (13 out of 14) and TOPs (13 out of 16) can override individual status telemetry, including tap positions. All respondents that have this feature rate it “essential” or “desirable” (13 out of 13 RCs and 13 out of 13 TOPs). Some RCs (6 out of 14) and TOPs (2 out of 16) can also override status telemetry, in bulk, from saved cases. This feature, which is useful in the event of an ICCP (or similar) data-link loss, appears to be more highly valued by RCs than TOPs; all 5 RCs but none of the TOPs rank this feature “essential” or “desirable.”

Fifty-seven percent of RC respondents (8 out of 14) and 27 percent of TOPs (4 out of 15) can define different voltage limits at each node and use the most restrictive limit for each resultant bus. Although 100 percent of those using this feature (7 out of 7 RCs and 4 out of 4 TOPs) consider it “essential” or “desirable,” fewer than one-third of the RCs and TOPs who do not have this feature rank it “desirable” (5 out of 17). There may be some confusion about the purpose and/or application of nodal voltage limits given the importance placed on them by those who use this feature in contrast to those who do not (and do not believe they need it).

Sixty-four percent of RCs respondents (9 out of 14) and 40 percent of TOPs (6 out of 15) can view chronologically all facility outages and returns. Almost all RCs (9 out of 9) and TOPs (5 out of 6) that have this feature use it. Of those using it, RCs unanimously (9 out of 9) rank it “essential,” and all TOPs (5 out of 5) rank it “essential” or “desirable.” Of those that do not have the feature, 80 percent of RCs (4 out of 5) and 55 percent of TOPs (5 out of 9) indicate that the feature would be “desirable.”

Support

The essential nature of network topology processing is evidenced by the number of respondents that have tools to monitor the status of this function and alert support staff to problems. As previously noted (Table 2.3-6), of those responding, 71 percent of RCs (10 out of 14) and 67 percent of TOPs (10 out of

15) can detect and independently notify operators and support staff that the NTP is down or functioning incorrectly. All 10 RCs and 10 TOPs with this feature consider it "essential" or "desirable," and 50 percent of RCs (2 out of 4) and 100 percent of TOPs (5 out of 5) that do not have the feature state that it would be "desirable."

A variety of support groups may get involved when NTP problems arise. The "System Operators and/or Other Control Room Staff" group is most commonly notified when NTP fails; 80 percent (8 of 10) of RCs and 60 percent of TOPs (6 of 10) notify this group. Operations support staff are often notified when NTP fails at RCs (7 of 10) but not at TOPs (only 1 of 10). The responses were more balanced for notification of EMS and/or information technology (IT) Support Staff; 5 of 10 RCs and 6 of 10 TOPs report using this strategy. Smaller numbers of respondents notify supervisory personnel or "Others." One company stated that "24/7 and on-site support staff are paged." See Table 2.3-7.

What Personnel are Notified of NTP Failures?	All	RCs
System Operators and/or Other Control Room Staff	14/20=70%	8/10=80%
Operations Support Staff	8/20=40%	7/10=70%
EMS and/or IT Support Staff	11/20=55%	5/10=50%
Supervisory and/or Management Staff	2/20=10%	2/10=20%
Other(s)	1/20=5%	1/10=10%

Table 2.3-7 — What Personnel are Notified of NTP Failures?

About 70 percent of those responding, including 80 percent of RCs (12 out of 15) and 57 percent of TOPs (8 out of 14), have tools to monitor NTP status and alert support personnel to problems. See Table 2.3-7. All RCs (12 out of 12) and TOPs (8 out of 8) that have this feature consider it "essential" or "desirable." Of those that do not have NTP Status Monitoring and Support Personnel Notification, 2 out of 3 RCs and 3 out of 6 TOPs rate this feature "desirable." All respondents that have the feature (12 RCs and 8 TOPs) monitor NTP support status 24x7x365. Roughly 40 percent of RCs (5 out of 12) and 38 percent of TOPs (3 out of 8) indicate that operators attempt to resolve problems prior to notifying support staff. Of those using NTP monitors, 92 percent of RCs (11 out of 12) and 75 percent of TOPs (6 out of 8) have support staff available continuously (24x7x365).

The survey responses indicate that support personnel notification procedures are well established and formalized, which suggests the importance respondents place on maintaining NTP's operational status. RCs and TOPs rely on multiple notification methods. Overall, two-thirds of those reporting, including 83 percent of RCs (10 out of 12) and 50 percent of TOPs (4 out of 8), indicate that the most common notification method is that operators process alarms and call support personnel as needed. The next-most-common method, used by about 50 percent overall, is to have support personnel on call, ready to connect remotely after business hours to fix problems as necessary [50 percent of RCs (6 out of 12), and 63 percent of TOPS (5 out of 8)]. Approximately 43 percent overall, with 42 percent of RCs (5 out of 12) and 50 percent of TOPs (4 out of 8) have support personnel on call who can report on site after business hours to fix reported problems. About one-third overall, including 4 out of 12 RCs and 3 out of 8 TOPs, rely on automatic paging systems activated by the application to notify support personnel of problems. Overall 33 percent, including 42 percent of RCs (5 out of 12) and 13 percent of TOPs (1 out of 8), have support staff on duty, monitoring applications continuously. One company resolves problems the next business day.

The majority of RCs and TOPs have de-bugging tools. See Table 2.3-8. Overall, program error logs and displays (13 out of 17) and program source codes (12 out of 17) are the most commonly used de-bugging tools. Embedded parameters/flags and code debugging software are used to a lesser extent. All RCs (11 out of 11) and 50 percent of TOPs (3 out of 6) with de-bugging tools rank them "desirable" or "essential," and 100 percent of RCs (4 out of 4) and 75 percent of TOPs (6 out of 8) that have no de-bugging tools indicate that these tools would be "Desirable." This suggests that improved de-bugging tools would be useful for NTP support. The tools currently available vary. Respondents who report having this feature tend to have multiple de-bugging tools.

What Types of De-Bugging Tools do You Have?	All	RCs
Do you have debugging tools for NTP?	18/31=58%	11/15=73%
Embedded debug parameters/flags that could be enabled/disabled	7/17=41%	5/11=45%
Program Error Logs and Displays	13/17=76%	8/11=73%
Program Source Code	12/17=71%	7/11=64%
Code Debugging Software	7/17=41%	5/11=45%
Other(s)	2/17=12%	2/11=18%

Table 2.3-8 — Types of De-Bugging Tools

In response to questions about NTP support activities, all respondents indicated that they assign in-house staff to NTP support (12 out of 12 RCs and 8 out of 8 TOPs); a few respondents involve vendors in support activities (3 out of 12 RCs and 0 out of 8 TOPs). For almost 40 percent of all respondents, including 42 percent of RCs (5 out of 12) and 20 percent of TOPs (1 out of 5), operators and support personnel use written procedures to fix NTP problems; about 67 percent of the RCs (8 out of 12) and 40 percent of TOPs (2 out of 5) use vendor documentation for this purpose. Some respondents state that customized displays, on-the-job experience, and specialized training are required for personnel to be proficient at diagnosing problems and de-bugging the application. Some respondents also perform regular manual NTP health checks using a combination of written procedures (6 out of 10 RCs and 0 out of 6 TOPs) and vendor documentation (2 out of 10 RCs and 3 out of 6 TOPs). In some cases, customized on-line displays assist with failure detection and de-bugging;

one company performs health checks when they notice discrepancies between map board and SCADA systems. No one uses interactive help guides for these purposes. See Section 2.4, Topology and Analog Error Detection, for a discussion of survey results regarding software tools that address metering/status inconsistencies, etc.

Recommendations for New Reliability Standards

RTBPTF considers NTP a mandatory tool for ensuring bulk electric system situational awareness. RTBPTF believes that NTP is of equal importance to the other mandatory tools such as the state estimator and contingency analysis, especially when used to drive alarming and visualization tools. Accordingly, RTBPTF recommends modifications to existing standards to clarify that use of NTP is mandatory (see the Reliability Toolbox Rationale and Recommendation section). In the following discussions, RTBPTF supports the major recommendation to make NTP mandatory.

The results of the RTBPTF survey detailed above support the assertion of Macedo (2004)[36] that a NTP is a minimum requirement — i.e., an essential tool for operators. NTP availability and recommendations are discussed in detail in the following subsections below.

Recommendation – S1

Mandate the following reliability tools as mandatory monitoring and analysis tools

- Alarm Tools
- Telemetry Data Systems
- Network Topology Processor
- State Estimator
- Contingency Analysis

Network Topology Processor: Mandatory Monitoring and Analysis Tool

Survey results indicate that NTPs are delivered as a standard part of commercially available, modern SCADA/EMS systems. Existing NERC reliability standards require the use of "adequate analysis tools" to aid operators in maintaining situational awareness for the bulk electricity system. Standard IRO-002 (Requirement R7) states "[e]ach Reliability Coordinator shall have ***adequate analysis tools*** [emphasis added] such as state estimation, pre and post-contingency analysis capabilities (thermal, stability, and voltage), and wide area overview displays." Specifying the NTP as part of the Reliability Toolbox[37] eliminates the vagueness in the current NERC reliability standards regarding

[36] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

[37] The Introduction to this report discusses the inclusion of the Network Topology Processor as part of the Reliability Toolbox.

whether NTP, as defined, is mandatory. The recommendation also provides clarity to the term "adequate analysis tools."

Recommendation – S8

Specify and measure minimum availability for network topology processor

Network Topology Processor Availability

The two main uses of the NTP are:

- To develop electric connectivity models as input to the state estimator, contingency analysis, or other analysis tools
- To generate operator displays for alarming and visualization (i.e., mapboards) of the status of elements of the bulk electric system (i.e., whether they are energized, open ended, or de-energized) as well as when electrical islands exist

For the first type of use, if an entity is using NTP only as an input to the state estimator, contingency analysis, or other analysis tools, the availability requirements for the state estimator[38] and contingency analysis[39] are sufficient to ensure that the entity's NTP is available. That is, if the entity's state estimator and contingency analysis are compliant per their respective availability standards, having a separate availability metric for NTP availability is unnecessary and redundant.

For the second type of use, RTBPTF recommends that reliability entities monitor the performance of their NTPs and measure availability because, for this use, the operators depend on NTP for situational awareness.

RTBPTF Recommendation

RTBPTF recommends that all RCs and TOPs be required to monitor the performance of their NTPs and measure availability when NTPs are used to generate operator displays for alarming and visualization (i.e., dynamic mapboards) of the status of elements of the bulk electric system (i.e., whether they are energized, open ended, or de-energized) as well as when electrical islands exist. RTBPTF believes that when NTP is used in this fashion, it needs to run more often and to be available.

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[38] The availability requirement for state estimator is discussed in detail Section 2.5.
[39] The availability requirement for contingency analysis is discussed in detail Section 2.6.

This recommendation shall only apply to entities that have stand-alone NTPs (i.e., a totally separate application that develops the electric connectivity models)[40] that drive alarm tools and visualization tools. RTBPTF recommends that a new requirement be established under the current Standard TOP-006 (Monitoring System Conditions) that shall apply to both RCs and TOPs and require NTP availability:

PR1. Network Topology Processor (NTP) Availability. Each Reliability Coordinator and Transmission Operator shall operate its NTP such that its NTP shall have at least one test topology change (or “watchdog” event) generated and processed at least every Telemetry Data System scan rate. This test event (or “watchdog” event) could originate from a test field device or could be application generated.

Although the NERC Standards process might address other factors in considering this recommendation, RTBPTF recommends the following measure for the requirement stated above:

PM2. Each Reliability Coordinator and Transmission Operator shall maintain NTP application logs, reports, or documents demonstrating that the Responsible Entity’s NTP processed the test topology change (or “watchdog” event) according to Requirement PR1.

Rationale

The electricity system behaves quite dynamically during the course of a day. NTP could be used to track changes in system configuration using algorithms that regularly analyze phenomena such as changing breaker and switch status in real time. The result is an accurate model of the current system configuration and preparation of data needed for other situational awareness tools. Used in this fashion, an available and robust NTP is essential to operators for timely detection of network topology changes. A metric to measure NTP availability provides a standardized method to measure performance.

Current Network Topology Determination

Standard IRO-005 (Requirement R1.1) states that each reliability coordinator shall monitor its reliability coordinator area parameters, including “[c]urrent status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection

[40] Some entities have a state estimator that has integrated the NTP functions and is not used for the purpose of alarming and visualization. Only stand-alone NTPs that drive alarm and visualization tools would have a required availability metric.

Systems) and system loading." RTBPTF recommends that Standard IRO-005 (Requirement R1.1) be modified to include a requirement that status information associated with transmission and generation elements be processed to determine current network topology. As a measure, topology results should be displayed to operators through alarms and visualization tools to indicate when equipment is disconnected, de-energized, or electrically isolated.

RTBPTF Recommendation

Standard IRO -005 (Requirement R1.1) should be modified as follows:

R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading. In addition, status information associated with transmission and generation Bulk Electric System and wide-area network elements shall be processed to determine current network topology. Results of the topology analysis shall be used to make operators aware of electrical islands and disconnected or de-energized equipment immediately after they are detected.

RTBPTF recommends the following measures for the modified requirement stated above:

PM1.1. Demonstrate that status change(s) are processed by NTP (or equivalent application[41]) to provide accurate configuration data before and after the change(s). Demonstrate that de-energized or disconnected equipment and formation of electrical islands are immediately displayed to operators via visualization tools.

Rationale

The task force survey results and comments make clear that NTP is an important, commonly used operator tool. NTP's primary functions include analyzing and establishing network topology and detecting electrical islands and disconnected or de-energized equipment. The *Outage Task Force Final Blackout Report* implies NTP's critical nature and importance for dynamically determining connectivity.

Several survey respondents' comments reinforce the importance of NTP. One respondent states that "local and wide area situation awareness would be very difficult to achieve, if at all, without network topology.

[41] Entities may used their Telemetry Data Systems (e.g., SCADA topology processing through Boolean logic equations/definitions) to provide topology detection functionality.

The task force recognizes that NTP functionality is multi-dimensional and that NTP is required to maintain the reliability of the bulk electric system. Topology analysis enhances operator situational awareness. Several survey respondents use NTP output independently of the network connectivity/topology to drive dynamic mapboards or other display devices that can serve as "outage display boards," as the sample quotes below indicate:

> "There is topology processing that is integrated into the State Estimator and the other network applications. We also have a SCADA topology processor that runs as part of the SCADA environment to indicate de-energized equipment based solely on SCADA information."

> "Topology outputs are used for mapboard indication and line, transformer outage alarming."

These activities directly support recommendations in Section 7 of the *Outage Task Force Final Blackout Report,* which compares the August 14, 2003 blackout with previous disturbances. In the discussion of System Visibility Procedures and Operator Tools, the report cites the following recommendation (among others) from previous investigations:

> In the control center, use a dynamic line loading and outage display board to provide operating personnel with rapid and comprehensive information about the facilities available and the operating condition of each facility in service.[42]

The task force agrees and recommends that standards be modified to support activities that drive outage display boards or other devices and tools and provide operating personnel with "rapid and comprehensive information about the facilities available."

Applicability Statement for Recommended Standards

RTBPTF recommends that all RCs and TOPs be required to have NTP for monitoring the status of bulk electric system equipment to analyze electrical connectivity in near real time and prepare electrical models for further analysis by the state estimator, contingency analysis, etc. as defined in the recommended additions or modifications to the NERC Standards applicable to RCs and TOPs. Other responsible entities that use network topology processors to support or complement their RCs' ability to operate the bulk electric system reliably in accordance with formal agreements, contracts, or established practices or procedures shall be subject to the same standards for NTPs as their RCs.

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[42] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p.108.

Recommendation – G3

Develop a chronological outage/return summary in network topology processor for recreating events and aiding state estimator.

Recommendations for New Operating Guidelines

In Section 2.9, Study Real-Time Maintenance, RTBPTF recommends the development of operating guidelines for study real-time maintenance applications. This capability is useful for maintaining highly available, accurate network analysis tools and supports the *Outage Task Force Final Blackout Report* Recommendation 37: "Improve IT forensic and diagnostic capabilities." The applications cited by RTBPTF as important to "improve IT forensic and diagnostic capabilities" should include NTP. About 50 percent (16 out of 30) of all survey respondents can view, chronologically, all facility outages and returns. Of the respondents that do not have this feature, 64 percent (9 out of 14) reported that it would be "desirable." RCs favored this feature more strongly than TOPs (100 percent of RCs rated it "essential.") A chronological outage/return summary is useful for recreating events and aiding state estimator troubleshooting. RTBPTF recommends that an Operating Guideline be developed for this NTP function.

Areas Requiring More Analysis

RTBPTF did not identify any Areas Requiring More Analysis related to NTP.

Examples of Excellence

The RTBPTF did not identify any Examples of Excellence related to NTP.

Section 2.4
Topology and Analog Error Detection

Definition

Topology and analog error detection (TAED) utilizes a computer application to identify and/or automatically override incorrect SCADA information regarding the statuses of breakers and switches. TAED is used to support NTP and improve the accuracy and robustness of the state estimator application. TAED also may identify and/or automatically ignore analog SCADA measurements that are unreasonable or inconsistent with network connectivity. Topology and analog error detection can serve as a pre-processor to other applications and can debug problems in the solutions those other applications produce. TAED can evaluate data, removing inconsistencies that may occur, for example, when direct information on equipment status indicates an open circuit while analog data suggests that power is flowing.

Background

This section of the report was developed to assess applications designed to eliminate or override incorrect or unreasonable status and/or analog data before NTP and the state estimator are executed. This pre-processing could enhance NTP and improve the quality of SE solutions.

TAED tools have great potential as pre-processors and debuggers for improving the performance of state estimator and other real-time tools. Although the industry would benefit from their universal use, their use currently is limited, perhaps because they are less effective than they need to be. TAED tools require redundant measurements in order to evaluate situations, identify inconsistent data, and provide accurate results. Developers of these tools should be encouraged to work with users to determine the model accuracy and measurement redundancy needed for the tools to perform well.

Because TAED is not used widely, RTBPTF does not consider this a critical reliability tool for operators and thus does not recommend creating or modifying reliability standards or operating guidelines to include TAED. RTBPTF does, however, recommend that TAED be analyzed further because this tool has potential to enhance NTPs and improve the quality of state estimator solutions.

Summary of Findings

Although TAED tools are available, the small number of survey responses makes it difficult to draw conclusions about industry-wide trends.

Survey responses and comments suggest that TAED tools are not generally used successfully, at least in part because there may be insufficient redundancy in the measurements available for analysis.

One respondent notes that "Topology Error Detection is used with our State Estimator. It has not proven very useful at this time. It works fairly well in well-measured parts of the system, but these were easy to detect before."

Section 2.3, Network Topology Processor, discusses in detail topics such as developing bus-branch models and detecting open equipment. In addition, some aspects of TAED are almost universally integrated into state estimator processes, as described in Section 2.5, State Estimator.

Prevalence and Perceived Value

Overall, 45 percent of those who responded to the TAED section of the Real-Time Tools Survey (21 out of 47) report having applications that provide TAED. This compares with 74 percent of respondents who reported having NTPs. RCs tend to use TAED more than do TOPs. Sixty-five percent of RCs (11 out of 17) report having operational TAED applications whereas just 27 percent of TOPs (7 out of 26) have operational TAED applications (1 TOP reports having a non-operational application). Two RCs and 4 TOPs indicate that they plan to acquire TAED.

The 9 respondents who submitted written comments on TAED convey a range of opinions about the application, as illustrated by the following quotations.

> "This feature allows RC1 to be aware of the telemetry which is not accurate. This improves situational awareness in monitoring the electrical power grid."
>
> "We've experienced some occurrences and it is useful but the occurrences are rare."
>
> "Topology Error Detection is used with our State Estimator. It has not proven very useful at this time. It works fairly well in well measured parts of the system, but these errors were easy to detect before."
>
> "Very essential."
>
> "On our system this is part of the state estimator preprocessing. It is not a stand alone application. Analogs and statuses that are inconsistent are identified in the application logs."
>
> "We don't have Topology Error Detection."
>
> "The use of a topology and analog error detection algorithm is one of the most important tools of our advance tools. It provides us the information to correct any measurement and false switch states. We can then send the right topology to our state estimator."

"Debugging solution problems without analog error detection would be very difficult, if not impossible in a r/t time line."

"Topology error detection is a separate function from analog error detection. Only analog error detection is functional at this time."

Availability and Interface with Other Applications

Survey results suggest that users can easily purchase TAED applications. Ten out of 11 RCs and all 7 TOPs that have operational applications report that their TAED software is "off-the-shelf" or "off-the-shelf with some customization." No one reports using applications that are highly customized or developed in house. As might be expected, the RCs and TOPs that have software supplied by their EMS vendors note that it is fully integrated with SCADA/EMS. Of 2 RCs who report having third-party products, one indicates that the package is fully interfaced with EMS, and the other reports using a stand-alone TAED.

Table 2.4-1 illustrates the various applications that respondents report are interfaced with TAED.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, "32/38=84%" means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

TAED Interfaces	All	Reliability Coordinators
SCADA	11/20 = 55%	4/11 = 36%
Alarm tools	6/20 = 30%	2/11 = 18%
Monitoring and visualization techniques	7/20 = 35%	6/11 = 55%
Network topology processor	11/20 = 55%	7/11 = 64%
State estimator	19/20 = 95%	11/11 = 100%
Contingency analysis	7/20 = 35%	5/11 = 45%
Critical facility loading assessment	0/20 = 0%	0/11 = 0%
Power flow	8/20 = 40%	6/11 = 55%
Study real-time maintenance	5/20 = 25%	4/11 = 36%
Other(s)	1/20 = 5%	1/11 = 9%

Table 2.4-1 — TAED Interfaces

Users

System operators and other control room staff are the primary users of TAED applications, as reported by 73 percent of RCs (8 out of 11) and 71 percent of TOPs (5 out of 7). As shown in Table 2.4-2, operations support staff and EMS and/or IT support staff are variously identified as primary or secondary users. Supervisory and management staff are very infrequently identified as users.

Users	Who are Primary Users?		Who are Secondary Users?	
	All	RCs	All	RCs
System operators and/or other control room staff	13/20 = 65%	8/11 = 73%	4/18 = 22%	2/11 = 18%
Operations support staff	9/20 = 45%	7/11 = 64%	10/18 = 56%	7/11 = 64%
EMS and/or IT support staff	10/20 = 50%	4/11 = 36%	6/18 = 33%	2/11 = 18%
Supervisory and/or management staff	0/20 = 0%	0/11 = 0%	3/18 = 17%	1/11 = 9%
Other(s)	0/20 = 0%	0/11 = 0%	2/18 = 11%	2/11 = 18%

Table 2.4-2 — Users of TAED

Features and Functions

Of those responding, 82 percent of RCs (9 out of 11) and 67 percent of TOPs (4 out of 6) state that their TAED uses a topology-based algorithm. No respondents report that their TAED uses a Boolean logic approach; 32 percent of all RCs and TOPs (5 out of 17) report "other" approaches. One respondent comments that "Analog Error Detection is part of their [state estimator] SE solution," and others comment that they use a "vendor custom algorithm" or "State Estimator error processing."

Eight out of 12 RCs and all 7 TOPs indicate that their applications can detect incorrect statuses of breakers and switches. The perceived value of this feature is unclear, given that 4 RCs and 4 TOPs report it would be "desirable" to have, and 5 RCs who use the feature rate it "essential" or "desirable." In contrast, 3 out of the 8 RCs who have the feature don't use it, and 1 TOP indicates it has only minimal value. These responses may indicate that although the concept is good, current implementations are ineffective, that the "payback" does not justify use of the feature, or that the feature simply is not used widely.

Overall, 75 percent of respondents (6 out of 8) report that their TAED application detects inconsistent analog and status measurements. Sixty percent of RCs (3 out of 5) and 100 percent of TOPs (3 out of 3) note that they define bad status as occurring when the analog measurement (flow) is inconsistent with the status measurement. Sixty percent of RCs (3 out of 5) and zero TOPs report that they also define bad status as occurring when status is unavailable but surrounding measurements are available. Only 4 respondents report having and using the capability to automatically override bad status, suggesting that this feature currently has limited perceived value.

All respondents (all 12 RCs and 7 TOPs) report that their TAED applications are capable of detecting unreasonable and inconsistent analog SCADA values based on topology. The survey provided two examples of this ability: 1) detecting a zero-voltage measurement at an energized bus, or 2) detecting and identifying analog values that are inconsistent with each other, such as when the sum of power flows at a bus is not close to zero. Almost all RCs (11 out of 12) and all 7 TOPs who have this feature report that it is operational. Those who use the feature consider it "essential" or "desirable." Table 2.4-3 summarizes the reasonableness/consistency checks that TAED applications provide.

Reasonableness/Consistency Checks	All	RCs
Voltage out of limits	15/20 = 75%	9/11 = 82%
Large flow on open-ended or de-energized branches	12/20 = 60%	6/11 = 55%
Sum of power flows at a bus is near zero	9/20 = 45%	4/11 = 36%
Taps outside of range	8/20 = 40%	4/11 = 36%
Unit output outside of limits	8/20 = 40%	5/11 = 45%
Flow exceeds rating	8/20 = 40%	5/11 = 45%
Small flow on In-Service branches	5/20 = 25%	3/11 = 27%
Sign of loads	5/20 = 25%	2/11 = 18%
Large losses on branch	4/20 = 20%	1/11 = 9%
Flow has same sign on both ends of branch	3/20 = 15%	2/11 = 18%
Received flow is greater than sent flow on branch	3/20 = 15%	1/11 = 9%
Other(s)	2/20 = 10%	1/11 = 9%

Table 2.4-3 — Reasonableness/Consistency Checks

The only checks that at least 50 percent of all RCs and TOPs use are voltage out of limit and large flow on open-ended or de-energized branches.

Of the 12 RCs whose applications can ignore unreasonable analog data in the state estimator solution based on topology, 9 report having this feature operational. Of the 7 TOPs who have this capability, 6 report that it is operational. All 9 RCs and 6 TOPs who use the capability deem it "essential" or "desirable."

Overall, 80 percent of respondents report that their TAED systems execute periodically, including 9 out of 11 RCs (62 percent) and 6 out of 7 TOPs (85 percent). Five out of 11 RCs (45 percent) and 5 out of 7 TOPs (71 percent) report executing the application manually or based on SCADA events (change of status or rate-of-change). Only 3 RCs report executing the program in response to disturbance events. Fifty percent of RCs (4 out of 8) indicate they execute TAED after a manual override of data (as does 1 TOP) and after an invalid/suspect solution (as do 2 TOPs). Other triggers, such as those based on a schedule or other mechanism, are used less frequently. Several respondents comment that the application can be executed at the discretion of staff or in response to predefined breakers and analog rates of change.

Based on responses from 9 RCs, the application executes periodically at intervals that range from 60 seconds to 30 minutes, with 8 out of 9 RCs reporting periodic execution every 5 minutes or less. TOPs estimate intervals that range from 10 seconds to 15 minutes, with 5 TOPs indicating that periodic execution occurs every 5 minutes or less. Nine RCs report speeds of execution that range from 1 to 30 seconds, with 7 of the 9 reporting speeds of 10 seconds or less. Seven TOPs report speeds of execution that range from 1 second to 3 minutes, with 4 indicating that the application runs in 10 seconds or less.

Monitoring, Availability, and Support

The survey asked about the availability of users' TAED applications, including how software problems/failures are detected and what typical responses are to problems. Only 4 RCs and 4 TOPs indicate that they can automatically detect and independently notify operators and support staff that TAED is unavailable or functioning incorrectly, so no conclusions can be drawn about industry trends in automated detection and notification. Five RCs who don't have this capability, however, say it would be "desirable," and 100 percent of those who have the capability call it "essential."

Only 5 RCs and 3 TOPS responded to the remaining survey questions concerning the monitoring and reporting of the status of TAED applications. Overall, 80 percent of these respondents, including 4 RCs and 2 TOPs, report that TAED status is monitored continuously (24 hours per day, 365 days per year). Two RCs and 2 TOPs report that operators initially attempt to resolve problems although 60 percent of the time operators are not first responders. When problems occur, most frequently system operators and/or other control room staff are notified; however, 4 RCs report that EMS or IT support staff are notified, 2 RCs indicate that operations support staff are notified. All of those reporting indicate that support staff respond to problems within 15 minutes of being notified.

Only 4 RCs and 3 TOPs responded to questions about who maintains and supports the TAED application. All those responding indicate that in-house staff maintain and support TAED. One RC indicates that vendor staff also are involved in supporting the application.

Just 3 RCs and 1 TOP report having historical metrics to record how often the TAED application solves for a given number of runs, but all respondents consider the feature "essential" or "desirable." Two respondents indicate that statistics are measured automatically. (The survey defined TAED solutions as 100 percent available if, for every periodic execution within a given time period, TAED solves.) Three RCs and 4 TOPs who don't have these metrics consider them "desirable." Responses to survey questions about the mean time of TAED unavailability, acceptable duration of unavailability, and frequency and acceptable rates of failure were not statistically relevant (only 2 RCs and 1 TOP responded).

Few responses were received to questions about documentation and procedures. Overall, 56 percent (including 2 out of 4 RCs and 2 out of 3 TOPs) report using vendor documentation to guide operators and support personnel in fixing TAED problems. Only 3 RCs and no TOPs report using written procedures. A few comment that experienced staff members are needed to respond to problems and that those in support will "do what is needed."

Nearly 75 percent of responding RCs (8 out of 11) indicate they have tools to aid in debugging their TAED application whereas only 43 percent of the TOPs (3 out of 7) report having those tools. Only 6 RCs use the tools, but all 3 TOPs use them. All RCs (6) and TOPs (3) using the tools consider them "essential" or "desirable" and, overall, 6 out of 8 respondents who do not have debugging tools consider such tools "desirable."

Based on limited survey responses, debugging tools are most often available through program error logs and displays (5 out of 6 RCs and 2 out of 3 TOPs) although sometimes they are part of the program source code (3 out of 6 RCs and 2 out of 3 TOPs). Embedded debugging parameters/flags also can produce debugging output, according to 2 out of 6 RCs and 2 out of 3 TOPs. In addition, 3 out of 6 RCs and 1 out of 3 TOPs report having code debugging software. One respondent notes that they have "software that downloads EMS data and runs comparisons to identify analog errors."

Recommendations for New Reliability Standards

RTBPTF does not recommend any new reliability standards or modifications to existing standards related to TAED.

Areas Requiring More Analysis

The task force recommends that providers of TAED tools consult with their customers who use (or try to use) these tools to identify and address barriers to successful implementation. These tools have great potential for improving the performance of the state estimator and other critical real-time tools, and the industry would benefit from their wider use.

Examples of Excellence

The RTBPTF did not identify any Examples of Excellence related to TAED.

Section 2.5
State Estimator

Definition

A state estimator is an application that performs statistical analysis using a set of imperfect, redundant, telemetered power-system data to determine the system's current condition. The system condition or state is a function of several variables: bus voltages, relative phase angles, and tap changing transformer positions. A state estimator can typically identify bad analog telemetry, estimate non-telemetered flows and voltages, and determine actual voltage and thermal violations in observable areas. The state estimator application has two main uses. It provides:

1. a base case for reliability-analysis applications
2. input to other system monitoring tools

The state estimator solution is typically used as the base case for other reliability-related applications, such as contingency analysis. In some cases, the state estimator is used primarily as the basis for information communicated to operators regarding power system status; e.g., the state estimator drives the alarm application that alerts operators to power system events.

Background

The state estimator application has two main uses. It provides:

1. a base case for reliability-analysis applications
2. input to other system monitoring tools

RCs and TOPs must have current information about the status of their bulk electric system facilities (system visibility) and must also be aware of events and changes in facility status in neighboring systems (situational awareness). System visibility and situational awareness depend on software tools such as the state estimator and contingency analysis. The subsections below address the use of the state estimator to maintain situational awareness. Other sections of this report address other situational awareness tools, including contingency analysis.

State estimator algorithms filter telemetry data to resolve inherent errors in the meters used to record the data. State estimators use real-time measurements from telemetry data systems to formulate a complex mathematical model of the power system that reflects the network configuration. The state estimator then uses real-time system data to estimate the voltage and phase angle at each bus, which in turn are used to estimate real and reactive power flow through each line and transformer. With sufficient metering redundancy, state estimator results are theoretically more accurate than measurements themselves. The state estimator's equipment voltage and loading information is used by reliability analysis tools, such as contingency and power-flow analysis, to simulate various conditions and outages so that operators can evaluate bulk electric system reliability. In some cases, the state estimator solution (rather than telemetry data systems) is the primary monitoring information and interface to alarm tools.

State estimation is typically performed for areas within each RC's footprint (the "RC area") as well as areas just beyond the boundaries of the RC area to include facilities within the RC's "wide area." Section 2.2 of this report, Visualization Techniques, discusses the issues related to the monitoring of the "wide area," which is key to each RC's awareness of the interconnected grid. Sections 4.1, Model Characteristics, and 4.2, Modeling Practices and Tools, discuss modeling issues related to the wide-area view boundary.

For TOPs, who are not also RCs, the state estimator scope is typically local and focuses on the TOP's internal area of responsibility. Wide-area view is not required of TOPs; however, their local view must extend beyond their internal footprint to some degree because of the modeling required for them to perform robust contingency analyses.

The state estimator is one of the first major reliability analysis applications that processes data from telemetry data systems (i.e., systems that process SCADA and ICCP data) and provides operators with a solution showing the current state of the power system. If the state estimator fails, the reliability analysis applications that depend on it (e.g., contingency analysis, power flow) cannot run; in other words, system visibility is lost, and the operator cannot detect potential SOL or IROL violations. This problem is more profound if the state estimator is the operator's primary monitoring tool.

The state estimator section of the Real-Time Tools Survey attempts to obtain a snapshot of current state estimator availability and usage in the industry. The survey emphasizes reliability entities' (RCs', TOPs', BAs') current use of the state estimator for viewing/monitoring bulk electric system elements. The survey also addresses state estimator maintenance and support practices. Because state estimators are highly dependent on network models, this section of the report also highlights issues related to modeling and practices, particularly the external network model. RTBPTF classifies the state estimator as a critical real-time tool[43] and recommends additions and modifications to certain NERC reliability standards to ensure state estimator availability and solution quality.

The *Outage Task Force Final Blackout Report* describes state estimator use as follows:

[43] The concept of a critical real-time tool is explained in Section 5.4, Critical Applications Monitoring.

> Transmission system operators must have visibility (condition information) over their own transmission facilities, and recognize the impact on their own systems of events and facilities in neighboring systems. To accomplish this, system state estimators use the real-time data measurements available on a subset of those facilities in a complex mathematical model of the power system that reflects the configuration of the network (which facilities are in service and which are not) and real-time system condition data to estimate voltage at each bus, and to estimate real and reactive power flow quantities on each line or through each transformer. Reliability coordinators and control areas that have them commonly run a state estimator on regular intervals or only as the need arises (i.e., upon demand). Not all control areas use state estimators.[44]

The state estimator must be available, and its solution must be accurate for reliability entities to effectively monitor bulk electric system conditions. In analyzing the causes of the 2003 blackout, the *Outage Task Force Final Blackout Report* states,

> One of MISO's primary system condition evaluation tools, its state estimator, was unable to assess system conditions for most of the period between 12:15 and 15:34 EDT [August 14, 2003], due to a combination of human error and the effect of the loss of the Dayton Power and Light Stuart-Atlanta line on other MISO lines as reflected in the state estimator's calculations. Without an effective state estimator, MISO was unable to perform contingency analyses of generation and line losses within its reliability zone. Therefore, MISO could not determine that with Eastlake 5 down, other transmission lines would overload if FE lost a major transmission line, and could not issue appropriate warnings and operational instructions.[45]

NERC played an important role in the blackout investigation, and, as a result of the investigation findings, issued directives on February 10, 2004 to FE, MISO, and PJM to complete remedial actions by June 30, 2004 correcting deficiencies identified as factors contributing to the blackout. These directives focused on the state estimator and related applications. NERC required FE to ensure that its state estimator and contingency analysis functions "execute reliably full contingency analyses automatically every ten minutes or on demand," and are

[44] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 47.
[45] Ibid, p. 46.

used to notify operators of potential first contingency violations.[46] NERC also required that MISO fully implement and test its network topology processor to provide operating personnel a real-time view of system status for "all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems." MISO also had "to establish a means of exchanging outage information with its members and adjacent systems such that the MISO state estimator has accurate and timely information to perform as designed." NERC further required that MISO fully implement and test its state estimator and contingency analysis tools "to ensure they can operate reliably no less than every ten minutes."[47]

These NERC directives indicate the importance of the state estimator for maintaining system reliability.

Summary of Findings

The responses to the state estimator section of the RTBPTF survey reveal varying degrees of practice and implementation related to the state estimator application. The subsections below address survey findings regarding: usage of state estimators**,** applications that depend on state estimator solutions, features of state estimators, timing and length of state estimator runs, convergence rate and availability of state estimators, accuracy of state estimator solutions, monitoring of external facilities, presentation of state estimator results, and maintenance and troubleshooting of state estimators.

State Estimator Usage & Prevalence

A large percentage of survey respondents use state estimators. Seventy-five percent (36 out of 48) of respondents, including all RC respondents (17 out of 17), have a state estimator (Table 2.5-1). Ninety-seven percent (35 out of 36) of the respondents that have a state estimator, including all of the RCs (17 out of 17), say that it is operational (Table 2.5-2).

Do You Have State Estimator?	RC	Other	Total
Yes	17	19	36
No		12	12
All	**17**	**31**	**48**

Table 2.5-1 — Respondents that have a State Estimator

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U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p.152.

47 Ibid, Page 152.

Is Your State Estimator Operational?	RC	Other	Total
Yes	17	18	35
No		1	1
All	**17**	**19**	**36**

Table 2.5-2 — Respondents that have an Operational State Estimator

Seventy-five percent (9 out of 12) of respondents without a state estimator plan to add one in the future. Ninety-one percent (32 out of 35) of respondents with an operational state estimator rate it "essential" for situational awareness; 3 respondents, including 1 reliability coordinator, rated the state estimator "desirable."

Applications that Use the State Estimator Solution

The state estimator solution is a base case for contingency analysis for 94 percent (33 out of 35) of respondents and a base case for power flow for 97 percent (34 out of 35) of respondents. All RC respondents use the state estimator solution as a base case for contingency analysis and power flow. Eleven percent of respondents (4 out of 35) use the state estimator solution in locational marginal pricing applications. More than half of the 36 respondents who use state estimators use the base-case solution in offline power-flow applications. Twenty-nine percent (10 out of 35) of those who employ state estimators use the base case in their security-constrained economic dispatch application (see Table 2.5-3). Because multiple applications depend on the state estimator solution, it is essential that the state estimator be available and able to produce an accurate solution.

What Applications Use the State Estimator Solution as a Base Case?	RC	Other	Total
Contingency analysis	16	17	33
Voltage stability analysis	6	5	11
On-line/operator power flow	16	18	34
Off-line power flow	13	9	22
Study real-time maintenance	8	7	15
Locational marginal pricing	3	1	4
Security-constrained economic dispatch	7	3	10
Other(s)	2	2	4
Total	**16**	**19**	35

Table 2.5-3 — Applications that use State Estimator Solution as a Base Case

Respondents also use their state estimator solutions as input to monitoring tools. Table 2.5-4 shows the monitoring tools/applications that depend on the state estimator solution. RTBPTF believes that, as the performance of state estimators continues to improve, use of the state estimator solution in monitoring tools will increase. Table 2-5.4 shows the number of respondents whose state estimators interface with monitoring tools (i.e., driving the alarm tools application) Table 2.5-5 summarizes the usage of state estimators as monitoring tools. Most respondents use their state estimators to monitor MVA/Ampere loadings and low and high bus voltages.

Applications are Interfaced or Integrated With Your State Estimator	RC	Other	Total
SCADA	15	15	**30**
Alarm tools	15	13	**28**
Monitoring and visualization tools	15	13	**28**
Total	**16**	**19**	**35**

Table 2.5-4 — State Estimator Interface with Other Applications

Usage of State Estimator as a Monitoring Tool	RC	Other	Total
MVA/ampere loading	15	18	**33**
Low bus voltage	15	18	**33**
High bus voltage	15	18	**33**
Voltage drop	11	5	**16**
Voltage node angle separation	10	7	**17**
Other(s)	2	2	**4**
Total	**15**	**19**	**34**

Table 2.5-5 — State Estimator Used as Monitoring Tool

State Estimator Features

The survey asked respondents to describe features of their state estimators. The subsections below describe the data reported.

Customization & Application Integration

Table 2-5.6 summarizes the degree to which respondents' state estimators are customized. Table 2.5-7 summarizes responses regarding who developed state estimators for respondents. Table 2.5-8 summarizes the degree of state estimator integration. The results in these tables reflect the fact that good state estimators are commercially available; that is, major SCADA/EMS vendors can provide viable state estimators off the shelf with some customization.

Degree of State Estimator Customization	RC	Other	Total
Off the shelf with some customization	12	7	**19**
Off the shelf	3	8	**11**
Highly customized	2	3	**5**
Total	**17**	**18**	**35**

Table 2-5.6 — Degree of State Estimator Customization

State Estimator Developer	RC	Other	Total
Supplied by your SCADA/EMS vendor	15	16	**31**
Developed in house		2	**2**
Supplied by other vendor	2		**2**
Total	**17**	**18**	**35**

Table 2.5-7 — State Estimator Developer

Degrees of State Estimator Integration	RC	Other	Total
Fully integrated with your production SCADA/EMS system	15	18	**33**
Interfaced to your SCADA/EMS system	1		**1**
Stand alone	1		**1**
Total	**17**	**18**	**35**

Table 2.5-8 — Degree of State Estimator Integration

Algorithm Characteristics

The survey asked respondents whether their state estimators solve in one or two passes. Table 2.5-9 summarizes the responses, which indicate that the industry favors using a single-pass over a two-pass solution. According to Koress,[48] single-pass methods perform one estimation that simultaneously addresses internal and external networks. Among the drawbacks of single-pass state estimators are numerical instability problems and "smearing" of bad external system data to the internal system. An alternative one-pass method solves this problem by using a set of critical external pseudo-measurements. The two-pass method involves two state estimations: one for the internal system and another for the external system or for the entire system. Some versions of the two-pass state estimator require a load-flow study for the external system. Both two-pass approaches reduce the effects of boundary errors in the internal system solution by properly weighting the external pseudo-measurements, but they may result in very high or negative loads and generations in the external system.

State Estimator Algorithm	RC	Other	Total
Single Pass (Observable/internal network and non-observable/external network solved together)	12	12	24
Two-Pass (Observable/internal network and non-observable/external network solved separately)	5	6	11
Total	**17**	**18**	**35**

Table 2.5-9 — State Estimator Algorithm

The survey asked respondents how their state estimators handle zero-injection buses. Table 2.5-10 summarizes the results. Zero-injection buses are more commonly treated as high-confidence bus-injection measurements than as hard constraints.

[48] Koress, George N. 2002. "A Partitioned State Estimator for External Network Modeling," *IEEE Transactions on Power Systems*, Vol. 17, No. 3, August.

How Does Your State Estimator Treat Zero-Injection Buses?	RC	Other	All
Hard constraints	5	6	11
High-quality/confidence bus-injection measurements	11	11	22
Total	**16**	**17**	**33**

Table 2.5-10 — Treatment of Zero-Injection Buses

Convergence Tolerance Parameters

The survey asked respondents to identify their voltage-magnitude convergence-tolerance criteria (per unit) for their internal/observable systems (see Table 2.5-11) and for their external/unobservable systems (see Table 2-5.12).

Data	RC	Other	All
Average	0.0053	0.0253	0.0145
Median	0.0050	0.0099	0.0065
Max	0.0110	0.1000	0.1000
Min	0.0001	0.0010	0.0010
Std Dev	0.0042	0.0373	0.0270
Count	14	12	26

Table 2.5-11 — Voltage-Magnitude Convergence-Tolerance Criteria (per unit) for Internal/Observable System

Data	RC	Other	All
Average	0.0085	0.0226	0.0140
Median	0.00500	0.0100	0.0080
Max	0.0500	0.1000	0.1000
Min	0.0001	0.0010	0.0001
Std Dev	0.0126	0.0325	0.0230
Count	14	9	23

Table 2-5.12 — Voltage-Magnitude Convergence-Tolerance Criteria (per unit) for External/Unobservable System

The survey asked respondents to quantify their voltage-angle convergence-tolerance criteria (in radians) for their internal/observable systems (see Table 2.5-13) and their external/unobservable systems (see Table 2.5-14).

Data	RC	Other	All
Average	0.0078	0.0219	0.0143
Median	0.0050	0.0080	0.0063
Max	0.0350	0.1000	0.0100
Min	0.0005	0.0010	0.0001
Std Dev	0.5330	0.0369	0.0262
Count	14	12	26

Table 2.5-13 — Voltage-Magnitude Convergence-Tolerance Criteria (radians) for Internal/Observable Systems

Data	RC	Other	All
Average	0.0087	0.0189	0.0127
Median	0.0050	0.0100	0.0065
Max	0.0500	0.1000	0.1000
Min	0.0000	0.0001	0.0001
Std Dev	0.0124	0.0311	0.0216
Count	14	9	23

Table 2.5-14 — Voltage-Magnitude Convergence-Tolerance Criteria (radians) for External/Unobservable Systems

Periodicity of State Estimator Execution

The survey asked respondents to describe by what means they trigger their state estimators to run. Table 2.5-15 summarizes the data regarding triggering methods, and Table 2.5-16 details the responses from RCs only. The data in Table 2.5-15 show that 100 percent (35 out of 35) of respondents use periodic triggers for their state estimators. Seventy-one percent (25 out of 35) of respondents, including 71 percent (12 out of 17) of RCs, use manual triggers. Fifty-one percent (18 out of 35), including 59 percent (10 out of 17) of the RCs, use SCADA event triggers (i.e., breaker trips, analog rates of change).

State Estimator Triggering Method	RC	Other	All
Periodic Trigger	17	18	**35**
Manual Trigger	12	13	**25**
SCADA Event Trigger (change of status, rate-of-change, etc.)	8	10	**18**
Disturbance Event Trigger	1	3	**4**
Other(s)	1	2	**3**

Table 2.5-15 — State Estimator Triggering Method

State Estimator Trigger Type Used	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Periodic Trigger	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	18	**35**
Manual Trigger	X		X	X	X	X	X		X	X	X	X	X	X				13	**25**
SCADA Event Trigger	X	X	X	X	X	X	X	X										10	**18**
Other(s)		X																2	**3**
Disturbance Event Trigger	X																	3	**4**

Table 2.5-16 — State Estimator Triggering Method (detailed RC responses)

Respondents using a periodic trigger were asked to quantify it in seconds. Table 2.5-17 shows the descriptive statistics for state estimator trigger periodicity in seconds. Table 2.5-18 shows the frequency distribution for the same data. Macedo (2004)[49] says that state estimators should be triggered to execute every 2 minutes.

SE Trigger Periodicity (seconds)	RC	Other	All
Average	319	473	**396**
Median	300	300	**300**
Max	1,800	1,800	**1,800**
Min	30	60	**30**
Std Dev	399	506	**455**
Count	17	17	**34**

Table 2.5-17 — State Estimator Periodic Trigger Descriptive Statistics

[49] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

SE Trigger Periodicity (seconds)	RC	Other	All
30	1		1
60	2	2	4
90	2		2
120		2	2
180	1	1	2
300 (5 minutes)	9	8	17
420	1		1
900		2	2
1,500		1	1
1,800	1	1	2

Table 2.5-18 — State Estimator Periodic Trigger Frequency Distribution (seconds)

Respondents who use a manual trigger were asked what criteria they use to decide to trigger their state estimators. Table 2.5-19 shows the results for all respondents. Table 2.5-20 shows the responses for reliability coordinators only.

Trigger	RC	Other	All
After an invalid/suspect solution	10	7	**17**
After a system event	6	9	**15**
After a manual override of data	8	2	**10**
Other(s)	6	2	**8**
Based on a schedule	3	1	**4**

Table 2.5-19 — State Estimator Manual Trigger Criteria

If You Use a Manual Trigger, What Criteria do You Use to Decide to Manually Trigger SE?	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	Other	All
After an invalid/suspect solution	X	X	X	X	X	X	X	X	X	X						7	**17**
After a system event	X	X	X	X	X							X				9	**15**
After a manual override of data	X	X	X		X	X		X	X	X						2	**10**
Other(s)				X		X	X				X		X	X		2	**8**
Based on a schedule	X	X													X	1	**4**

Table 2.5-20 — State Estimator Manual Trigger Criteria (RCs Only)

State Estimator Execution Time (Performance)

The survey asked how long (wall clock time) it usually takes respondents' state estimators to solve. The average state estimator execution time for the 34 respondents to this question ranges from 1 second to 2 minutes. The average execution time for all respondents is about 20 seconds. The median execution time was 10.5 seconds for all respondents and 10 seconds for RC respondents. Average execution times are 10 seconds or shorter for half of the respondents' state estimators (17 out of 34), including 58 percent (10 out of 17) of the RCs' applications. Table 2.5-21 summarizes the results. Table 2.5-22 shows the frequency distribution for the same information.

State Estimator Solution Time (Wall Clock)	RC	Other	All
Average	21.0	19.4	**20.2**
Median	10.0	15.0	**10.5**
Max	120.0	60.0	**120.0**
Min	2.0	1.0	**1.0**
Std Dev	28.9	17.9	**23.7**
Count	17.0	17.0	**34.0**

Table 2.5-21 — State Estimator Solution Time (wall clock time in seconds) Descriptive Statistics

State Estimator Solution Time (Wall Clock)	RC	Other	All
1-10	10	7	17
11-20	4	6	10
21-30	1	1	2
>30	2	3	7
Total	17	17	34

Table 2.5-22 — Frequency Distribution for State Estimator Solution Time (wall clock time, in seconds)

State Estimator Convergence Rate and Availability

The survey asked respondents to identify their convergence rate metrics and tools. Table 2.5-23 summarizes the results. Fifty percent (17 out of 34) of the respondents, including 53 percent (9 out of 17) of the RC respondents, have state estimator convergence rate metrics as well as tools to compute these metrics.

Do You Have Convergence Rate Metrics and Tools?	RC	Other	All
Yes	9	8	**17**
No	8	9	**17**
Total	17	17	**34**

Table 2.5-23 — State Estimator Convergence Rate Metrics and Tools

The survey asked respondents to indicate how their convergence rates were measured. Of those that responded, 50 percent (8 out of 16), compute the state estimator convergence rate automatically. Table 2.5-24 summarizes the responses. Table 2.5-25 summarizes the time period(s) for which state estimator convergence rates are measured, with detailed data for the reliability coordinator respondents. For respondents that measure state estimator convergence rate, the most common time interval is 1 month. Forty-four percent (4 out of 9) of the reliability coordinator respondents track state estimator convergence rate over multiple time intervals.

How is Your State Estimator Convergence Rate Measured?	RC	Other	All
Automatically	4	4	**8**
Manually	2	3	**5**
Other(s)	3		**3**
Total	9	7	**16**

Table 2.5-24 — State Estimator Convergence Rate Measurement

For What Time Periods is Your State Estimator Convergence Rate Measured? (Please check all that apply and specify a % solution rate for that time period.)	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	Others	All
Previous Month(s)	X		X			X	X			4	**8**
Previous Hour(s)	X	X	X		X					2	**6**
Previous Week(s)	X	X								1	**3**
Previous Year(s)	X	X						X		0	**3**
Rolling Time Period(s)				X						1	**2**
Selected Time Period(s)				X					X	1	**3**

Table 2.5-25 — Time Periods for State Estimator Convergence Rate Measurements

The survey asked the approximate distribution of respondents' state estimator availability. Table 2.5-26 summarizes the average percentage of time during which state estimators are not available within each duration range. The average period during which state estimator solutions are unavailable is 15 minutes or less for more than 95 percent of all respondents and more than 93 percent of RCs. Note that most respondents -- sixty percent (9 out of 15), and 78 percent (7 out of 9) of RC respondents -- estimate unavailability periods rather than computing them from historical data.

Duration of state estimator unavailability — distribution	RC	Other	All
≤ 15 minutes	93.6	98.5	95.5
15 - 30 minutes	4.1	1.2	3.0
30 - 60 minutes	1.0	0.0	0.7
1 - 4 hours	0.5	0.3	0.4
> 4 hours	0.8	0.0	0.4

Table 2.5-26 — Frequency Distribution of State Estimator Unavailability

The survey asked respondents to indicate how long the state estimator would have to be unavailable to have "significant impact" on their system operations. Table 2.5-27 summarizes the responses. Thirteen percent (2 out of 15) of respondents, including 11 percent (1 out of 9) of RCs, consider unavailability of up to 30 minutes as having no significant impact on operations. Eighty-nine percent (8 out of 9) of the RC respondents cited a "reliability requirement" as the basis for their state estimator unavailability metric. All 6 of the other respondents cited an “internal policy requirement” as the basis for their state estimator unavailability metric. Forty-four percent (4 out of 9) of the RC respondents and 50 percent (3 out of 6) of the other respondents cited market application requirements.

What is the Length of Unavailability That You Consider to Be a Significant Impact on Your System Operation? More than ...	RC	Other	All
1 minute		1	1
10 minutes	1		1
15 minutes		1	1
20 minutes	2	3	5
30 minutes	5		5
60 minutes	1	1	2
Total	**9**	**6**	**15**

Table 2.5-27 — State Estimator Unavailability Considered “Significant” Impact on Operations

Table 2.5-28 summarizes the frequency of state estimator failures that respondents perceive as having a “significant” impact on system operations. Eighty-one percent (13 out of 16) of respondents, including 78 percent (7 out of 9) of RC respondents, experience either occasional or rare state estimator failures that have a significant impact on their operations. Nineteen percent (3 out of 16) of respondents, including 22 percent (2 out of 9) of RC respondents have frequent or very frequent state estimator failures that impact system operations.

Which Best Describes the Frequency of State Estimator Failures That Have a Significant Impact on Your System Operation?	RC	Other	All
Rare — At least one per year on average	3	5	**8**
Occasional — At least one per month on average	4	1	**5**
Very frequent — At least one per day on average	1	1	**2**
Frequent — At least one per week on average	1		**1**
Total	**9**	**7**	**16**

Table 2.5-28 — Frequency of State Estimator Unavailability Considered “Significant” Impact on Operations

State Estimator Solution Quality (Accuracy)

One hundred percent of respondents can detect and identify bad analog measurements and remove them from the state estimator measurement set. The survey asked respondents to quantify the real/reactive power mismatch tolerance criteria for their internal/observable systems. Respondents report a 0.05-170 MW real power mismatch tolerance range and a 0.001-500 Mvar reactive power mismatch tolerance range. The average real and reactive mismatch tolerance criteria were 35 MW and 69.5 Mvar, respectively. Table 2.5-29 summarizes the state estimator convergence criteria for internal system MW mismatch. Table 2.5-30 summarizes the state estimator convergence criteria for internal system Mvar mismatch. The results in Table 2.5-29 and Table 2.5-30 are suspect because zero-injection buses are not treated consistently by all respondents (see Table 2.5-10). Respondents that treat zero-injection buses as hard constraints would be expected to indicate very low real/reactive mismatch tolerances whereas respondents treating zero-injection buses as high-confidence measurements would be expected to have reasonable real/reactive mismatch tolerance values.

Data	RC	Other	All
Average	43.20	17.10	35.00
Median	30.00	1.00	15.00
Max	170.00	50.00	170.00
Min	0.05	0.10	0.05
Std Dev	51.10	25.50	45.60
Count	13.00	6.00	19.00

Table 2.5-29 — State Estimator Convergence Criteria for Internal System MW Mismatch

Data	RC	Other	All
Average	93.700	16.300	69.500
Median	50.000	1.000	40.000
Max	500.000	50.000	500.000
Min	0.001	0.100	0.001
Std Dev	144.300	22.700	124.000
Count	11.000	5.000	16.000

Table 2.5-30 — State Estimator Convergence Criteria for Internal System Mvar Mismatch

The survey asked respondents to quantify the real/reactive power mismatch tolerance criteria for their external/unobservable systems. Respondents report a 0.05-999 MW real power mismatch tolerance range and a 0.001-9999 Mvar reactive power mismatch tolerance range. The average real and reactive mismatch tolerance criteria were 614.7 MW and 665.7 Mvar respectively. Table 2.5-31 summarizes the state estimator convergence criteria for external system MW mismatch. Table 2.5-32 summarizes the state estimator convergence criteria for external system Mvar mismatch. As in the case for the internal/observable system, the results in Table 2.5-31 and Table 2.5-32 are suspect because zero-injection buses are not treated consistently by all respondents (see Table 2.5-10). Respondents that treat zero-injection buses as hard constraints would be expected to indicate very low real/reactive mismatch tolerances values whereas respondents that treat zero-injection buses as high-confidence measurements would be expected to have reasonable real/reactive mismatch tolerance values.

Macedo (2004)[50] states that state estimator MVA mismatch should be less than 10 MVA. He does not distinguish between internal and external systems.

Data	RC	Other	All
Average	138.40	1,431.10	614.70
Median	40.00	1.00	10.00
Max	999.00	9,999.00	9,999.00
Min	0.05	1.00	0.05
Std Dev	279.00	3,778.00	2,283.00
Count	12.00	7.00	19.00

Table 2.5-31 — State Estimator Convergence Criteria for External System MW Mismatch

Data	RC	Other	All
Average	219.200	1,431.100	665.700
Median	70.000	1.000	10.000
Max	999.000	9,999.000	9,999.000
Min	0.001	1.000	0.001
Std Dev	370.000	3,778.000	2,280.000
Count	12.000	7.000	19.000

Table 2.5-32 — State Estimator Convergence Criteria for External System Mvar Mismatch

Table 2.5-33 summarizes respondents' state estimator solution quality (accuracy) metrics, showing detailed responses for RCs. The most commonly used state estimator solution quality metric, cost index, is used by 45 percent (10 out of 22) of all respondents and 58 percent (7 out of 12) of RC respondents. The second most commonly used metric is Chi-Squared criteria, used by 36 percent (8 out of 22) of all respondents and 42 percent (5 out of 12) of RC respondents. These metrics are a basis for RTBPTF's recommendation for operating guidelines related to state estimator solution quality.

[50] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

What is Your Metric for Assessing the Accuracy of the Results of Your State Estimator Application? (Please check all that apply.)	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	Other	Total
Use cost index as a performance indicator	X	X	X	X			X				X	X	3	**10**
Use Chi-Squared criteria as performance indicator		X	X			X	X	X					3	**8**
Use measurement error/bias analysis as a performance indicator			X						X	X			4	**7**
Use average residual value as a performance indicator	X												1	**2**
Other(s)	X	X			X								3	**6**

Table 2.5-33 — State Estimator Solution Quality (Accuracy) Metrics

Table 2.5-34 summarizes respondents' methods for assessing state estimator solution quality. These methods are not formalized assessment processes.

What is Your Method for Assessing the Accuracy of the Results of Your State Estimator Application?	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	Other	All
Continually monitor and minimize the amount of bad data detected by correcting model, telemetry, and bad statuses	X	X	X	X	X	X	X	X	X	7	**16**
Compare critical telemetry with the state estimator solution (ties, major lines, large units, etc.)	X	X	X	X	X	X		X	X	7	**15**
Use measurement error/bias analysis to detect and resolve telemetry and model problems			X	X	X	X	X	X		8	**14**
Periodically review all stations to correct high residuals and minimize all residuals as much as reasonably possible	X	X	X			X	X		X	5	**11**
Compare contingency analysis results to actual system	X	X	X	X	X	X	X		X	2	**10**
Compare power-flow results to actual system	X	X		X	X	X		X		2	**8**
Compare state estimator actual violations to see if they closely match actual SCADA violations	X	X	X	X	X		X			2	**8**
Compare state estimator total company load/ generation/ interchange integrated over time to see if it closely matches billing metering	X	X	X							0	**3**
Others										1	**1**

Table 2.5-34 — Methods for Assessing State Estimator Solution Quality (Accuracy)

Measurement weights (confidences) are important parameters used in the state estimator application that could significantly affect its solution. The survey asked respondents to define weights for telemetered measurements. Table 2.5-35 shows that 78 percent (8 out of 11) of all respondents, including 80 percent (4 out of 5) of RC respondents, use individually defined weights for at least some of the telemetered measurements used by their state estimators. Thirty-six percent (4 out of 11) of all respondents, including 60 percent (3 out of 5) of RC respondents, use globally defined weights for at least some of the telemetered measurements used by their state estimators. The survey also asked respondents to define measurement weights for non-telemetered measurements. Table 2.5-36 summarizes the responses. Fifty-five percent (6 out of 11) of all respondents, including 60 percent (3 out of 5) of RC respondents, use globally defined weights for at least some of the non-telemetered measurements used by their state estimators (i.e., modeled loads and generator outputs). Fifty-five percent (6 out of 11) of the respondents, including 60 percent (3 out of 5) of RC respondents, use individually defined weights for at least some of the non-telemetered measurements used by their state estimators (i.e., modeled loads and generator outputs).

How do You Define Measurement Weights for Telemetered Measurements?	RC01	RC02	RC03	RC04	RC05	Others	Total
Measurements have individually defined weights		X	X	X	X	4	**8**
Globally defined weights by measurement type (e.g., line measurements, transformer MW/Mvar)	X		X		X	1	**4**
Others						1	**1**

Table 2.5-35 — Weights for Telemetered Measurements

How do You Define SE Measurement Weights for Non-Telemetered Measurements? (Please check all that apply.)	RC01	RC02	RC03	RC04	RC05	Others	All
Globally defined weights by type (e.g., non-telemetered loads, non-telemetered generators)	X		X		X	3	**6**
Measurements have individually defined weights			X	X	X	3	**6**
Other(s)		X					**1**

Table 2.5-36 — Weights for Non-Telemetered Measurements

The survey asked respondents to characterize their basis for assigning weights to model measurements. Table 2.5-37 summarizes the responses for SCADA analog measurements (excluding measurements from ISN and other data links). Forty-five percent (5 out of 11), including 60 percent (3 out of 5) RC respondents, use generic percentage metering errors as the basis for weights applied to at least some analog values used by their state estimators. Twenty-seven percent (3 out of 11), including 40 percent (2 out of 5) of RC respondents, use actual meter accuracies as the basis, and 27 percent (3 out of 11) use other methods besides actual meter accuracies or generic meter error percentages.

What is the Basis for Your SCADA Analog Measurement Weights (excluding measurements from ISN and other data links)?	RC01	RC02	RC03	RC04	RC05	Others	All
Generic percentage meter error for each measurement type	X			X	X	2	**5**
Actual meter accuracies associated with each individual measurement						3	**3**
Other(s)		X	X			1	**3**

Table 2.5-37 — Basis for SCADA Analog Measurement Weights

Using State Estimator to Monitor External Facilities

Monitoring external facilities using the state estimator is highly dependent on the modeling practices related to external facilities. State estimator solution quality including external facilities depends on the accuracy with which external facilities are modeled. Section 4.1, Model Characteristics, and Section 4.2, Modeling Practices and Tools, discuss external system modeling practices in detail.

The external network models that are currently in use could affect the quality of state estimator solutions by:

- **Propagation of errors into the internal model solution from the external model solution**. This concern applies to one-pass state estimators if the external network model solution is mainly based on forecasted and/or pseudo-measurements rather than telemetered data. The external network model equivalencing methodology could also cause errors to propagate. For systems that use a two-pass state estimator, there could be boundary problems (between the internal/observable solution and the external/unobservable solution) that could cause the total network solution to not converge.

- **Measurement density in the external system**. Findings in Section 4.1 indicate that many buses in external models are measurement unobservable. The low values for the external-status-point-to-external-bus ratios for many respondents (i.e., less than one status point per bus) indicates that many external buses do not have telemetered breaker/switch information, which implies a bus-branch type external model (i.e., a planning model) for many buses. The lack of real-time telemetry data in MISO's external model was one of the contributing factors in the 2003 blackout. The *Outage Task Force Final Blackout Report* indicates that MISO was using a static bus-branch network model in parts of its external model. When the Stewart- Atlanta 345-kV line tripped (monitored by the PJM reliability coordinator), MISO's state estimator did not know the line had gone out of service. This led to a data mismatch that prevented MISO's state estimator from computing a solution that could be used by its real-time contingency analysis application.[51]

- **Convergence issues related to external models and/or telemetry data for external model**. Measurements for the external network model usually originate from ICCP (or equivalent) data links. Therefore, data availability depends on data-link availability. Another factor is the time skew of data supplied by the external network model measurements; time skew is highly dependent on the periodicity of the data-link data.

- **Interchange transaction impacts.** The impact of interchange transactions, especially for the external portion of the model, could greatly affect the state estimator solution.

- **Throughput because of external model expansion/detail**. Adding detail or expanding the external network model could affect the throughput (execution time) of the state estimator application.

In response to the 2003 blackout, many survey respondents are expanding and/or adding more detail to their external network models. As mentioned in Section 4.1, Model Characteristics, approximately 88 percent (15 out of 17) of RC respondents and 75 percent (18 out of 24) of other respondents indicate that in the coming year they plan to make "major" changes to their network models above and beyond what is considered "routine" model maintenance. Table 2.5-38 summarizes the types of changes planned. These changes will greatly impact state estimator solution quality. The observations cited in Table 2.5-38 suggest that most near-term major changes will be related to external network model improvements. For RCs, these types of changes will enhance wide-area analysis capabilities provided by the reliability analysis applications recommended by Macedo (2004)[52.]

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[51] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 46.

[52] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

Major Model Changes in Coming Year	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	Others	Total
Adding breaker/switch detail to the external model	X	X	X	X			X	X	X							7	**14**
Adding breaker/switch detail to the internal model	X	X	X	X	X											7	**12**
Adding extensive telemetry to the external model	X	X	X			X	X	X	X							6	**13**
Adding extensive telemetry to the internal model	X	X		X	X	X							X			3	**9**
Adding lower voltage detail to the external model	X									X						3	**5**
Adding lower voltage level detail to the internal model	X	X	X	X												4	**8**
Adding one or more control areas to the external model	X					X										3	**5**
Creating a new external model	X									X	X	X			X	10	**15**
Others			X		X						X			X		5	**9**

Table 2.5-38 — Major Model Changes Planned for Coming Year

The survey asked respondents to characterize their basis for assigning weights to model measurements from ISN and other data links (i.e., external model measurements). Table 2.5-39 summarizes the responses, showing that 78 percent (8 out of 11) of all respondents and 60 percent (3 out of 5) RC respondents use generic metering error percentages as the basis. Twenty-seven percent (3 out of 11), including 40 percent (2 out of 5) of RC respondents, use something other than generic percentages or actual metering errors as the basis.

What is the Basis for Your Measurement Weights From ISN and Other Data Links?	RC01	RC02	RC03	RC04	RC05	Other	All
Generic percentage meter error for each measurement type	X			X	X	5	**8**
Other(s)		X	X			1	**3**

Table 2.5-39 — Basis for ISN (and other data link) Analog Measurement Weights

Presentation of State Estimator Results

The survey asked respondents to describe how their state estimator solution is presented in visualization tools (i.e., state estimator one-line displays). (Section 2.1, Visualization Techniques, of this report discusses usage and prevalence of state estimator one-line displays.) Of the 35 respondents that have working state estimators, 97 percent (34 out of 35), including 100 percent (17 out of 17) of RC respondents, use some type of state estimator one-line display. Sixty-five percent (22 out of 34) overlay the state estimator values on SCADA one-line displays so that estimated values can be seen along with raw values. Thirty-five percent (12 out of 34) display state estimator results separately from SCADA one-lines. Among RC respondents, 47 percent (8 out of 17) overlay state estimator results on existing SCADA one-line displays, and 53 percent (9 out of 17) display state estimator results on separate one-line displays. Table 2.5-40 summarizes the results.

State Estimator One-Line Displays	RC	Other	All
State estimator one-lines are overlays of SCADA one-lines	8	14	**22**
State estimator one-lines are separate from SCADA one-lines	9	3	**12**
Do not have state estimator one-lines	0	1	**1**
Total	17	18	**35**

Table 2.5-40 — Presentation of State Estimator Results

State Estimator Maintenance/Troubleshooting Practices

The majority of respondents can notify operators and control room staff of a state estimator failure. State estimator status is presented primarily via alarm tools and physical displays although a few respondents can page and send email.

The survey asked respondents whether they have a process to investigate and de-bug unsolved/non-converged and bad/inaccurate state estimator solutions. Ninety-four percent (29 out of 31) of those that responded, including 94 percent (15/16) of RC respondents, investigate unsolved state estimator solutions. Table 2.5-41 summarizes the responses.

Do You Investigate Unsolved or Non-Converged State Estimator Solutions?	RC	Other	All
Yes	15	14	**29**
No	1	1	**2**
All	16	15	**31**

Table 2.5-41 — Investigation of Unsolved or Non-Converged State Estimator Solutions

The survey also asked respondents whether their operators attempt to resolve state estimator problems prior to notifying support personnel. Table 2.5-42 summarizes the results. Fifty-three percent (15 out of 28) of all respondents, including 60 percent (9 out of 15) of RC respondents, have operators attempt to resolve state estimator convergence problems prior to notifying EMS support personnel.

Do Operators Attempt to Resolve State Estimator Problems Prior to Notifying Support?	RC	Other	All
Yes	9	6	**15**
No	6	7	**13**
Total	15	13	**28**

Table 2.5-42 — State Estimator Problem-Resolution Practices

The survey asked respondents about state estimator maintenance and support. Table 2.5-43 summarizes the responses. The table illustrates that 100 percent (28 out of 28) of all respondents, including 100 percent (15 out of 15) of RC respondents maintain their state estimators with in-house staff. However, 18 percent (5 out of 28), including 27 percent (4 out of 15) of RC respondents, use vendor staff in addition to in-house staff for support.

Who Maintains Your State Estimator?	RC	Other	All
In-House Staff	15	13	**28**
Vendor Staff	4	1	**5**

Table 2.5-43 — State Estimator Maintenance and Support

The survey asked respondents whether they continuously monitor the status of their state estimators (i.e., 24 hours per day, 7 days per week, 365 days per year). Table 2.5-44 summarizes the responses. Seventy-five percent (27 out of 36) of all respondents that have operational state estimators responded to this question. Of those that responded, 89 percent (24 out of 27), including 93 percent (14 out of 15) of RC respondents, continuously monitor state estimator status 24 x 7 x 365. The respondents were also asked whether their state estimator support personnel are available continuously (24 x 7 x 365). There were 28 respondents to this question, including 15 RCs; Table 2.5-45 summarizes the results. Ninety-three percent (26 out of 28) of all respondents, including 93 percent (14 out of 15) of RC respondents, have state estimator support personnel available continuously.

Is the Status of Your State Estimator Monitored Continuously (24 x 7 x 365)?	RC	Other	All
Yes	14	10	**24**
No	1	2	**3**
Total	**15**	**12**	**27**

Table 2.5-44 — State Estimator Application Monitoring

Are Your State Estimator Support Personnel Available Continuously (24 x 7 x 365)?	RC	Other	All
Yes	14	12	**26**
No	1	1	**2**
Total	**15**	**13**	**28**

Table 2.5-45 — State Estimator Support Personnel Availability

Table 2.5-46 summarizes how support personnel are notified of state estimator problems. A majority of respondents, 79 percent (22 out of 28), including 87 percent of RC respondents, send an alarm to their operators. The operators then contact support personnel as needed to correct the problem. Sixty percent (17 out of 28) of all respondents, including 60 percent of RC respondents, have support personnel on call who can connect to the EMS remotely after business hours to fix reported problems. Only 7 respondents, which included 6 RCs, have support personnel on duty that continually monitor the state estimator.

How Are Your State Estimator Support Personnel Notified of Problems? (Please check all that apply.)	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	Other	All
The operator receives an alarm and then calls for support personnel.	X	X	X	X	X	X	X	X		X	X	X	X	X		9	**22**
Support personnel are on call and connect remotely after business hours to fix reported problems.	X	X		X	X		X	X	X			X		X		8	**17**
Support personnel are on call and report on site after business hours to fix reported problems.	X	X	X		X			X			X		X	X		4	**12**
Support personnel are automatically paged by the application(s).	X	X	X	X	X	X	X									3	**10**
Support personnel are staffed on shift and monitor applications continuously.	X	X	X	X		X				X						1	**7**
Other(s)															X	0	**1**

Table 2.5-46 — State Estimator Support Personnel Notification Methods

Recommendations for New Reliability Standards

The state estimator is mainly used:

- as a base case for reliability analysis applications (e.g., contingency analysis, power flow), and
- as input to other operator monitoring tools (e.g., alarm, wide-area visualization).

Wollenberg (2006)[53] says:

[53] Wollenberg, Bruce. 2006."ERO Standards: What Should They Cover." *IEEE Power & Energy Magazine*, Volume 4 (4), July/August: 96.

> The state estimator is the first of the major application programs that runs as new data are gathered from the power system into an operations computer system. If the state estimator fails, then the remaining applications ([optimal power flow] OPF, security analysis, etc.) cannot be run — the operator is blind. To quote Brian Stott, "By now, it ought to be (and is not) a SCANDAL if a company's state estimator does not produce a reliably accurate real-time power system model virtually 100% of the time." So what does it take to achieve a 100% reliable state estimator? First it takes a well-thought-out and maintained metering system, a well-maintained communications system, a constantly updated database containing the power system model, and, last of all, a state estimator algorithm designed not to fail when some critical measurements are missing.

The results of the RTBPTF survey detailed in the previous section support the assertion of Macedo (2004)[54] that a state estimator is a minimum requirement, i.e., an essential tool for operators. Figure 2.5-1 shows a slide from Macedo (2004) on the topic of network analysis, which implies that a state estimator should execute every two minutes and should have a solution accuracy of less than 10 MVA mismatch. RTBPTF agrees with Macedo's assessment that a state estimator is a minimum requirement (i.e., a critical real-time tool) but does not agree that the state estimator needs to execute every 2 minutes at a minimum. In lieu of measuring the triggering periodicity of state estimator, RTBPTF recommends measuring state estimator availability (for a given, reasonable periodicity required by other reliability analysis applications). RTBPTF also recommends measuring state estimator solution quality. RTBPTF believes that state estimator availability and adequate solution quality are measures that can ensure a robust and accurate reliability monitoring tool for operators. The state estimator availability and state estimator solution quality recommendations are discussed in detail in the following subsections below.

[54] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

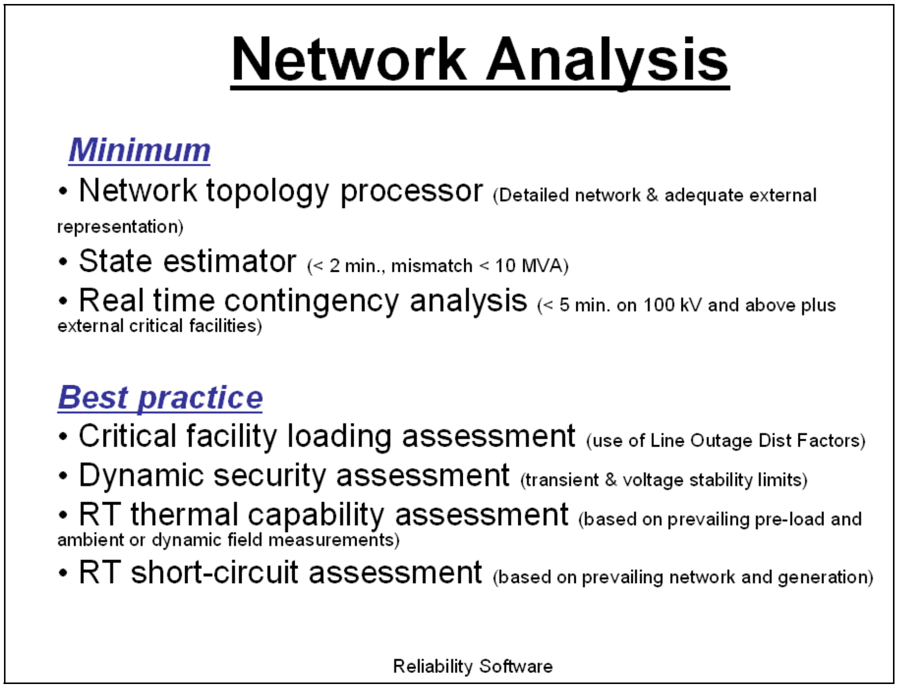

Figure 2.5-1 — Copy of Slide on Network Analysis (Macedo 2004)

Recommendation – S1

Mandate the following reliability tools as mandatory monitoring and analysis tools

- Alarm Tools
- Telemetry Data Systems
- Network Topology Processor
- State Estimator
- Contingency Analysis

State Estimator: Mandatory Monitoring and Analysis Tool

Survey results indicate that state estimators are inherently delivered as part of commercially available modern SCADA/EMS systems. RTBPTF believes that a state estimator is essential for operators to monitor and maintain the reliability of the bulk electric system. Existing NERC reliability standards implicitly assume the use of state estimators to aid RCs and TOPs in maintaining situational awareness for the bulk electric system. Standard IRO-002 (Requirement R7) states "[e]ach Reliability Coordinator shall have ***adequate analysis tools*** [emphasis added] such as ***state estimation*** [emphasis added], pre and post-contingency analysis capabilities (thermal, stability, and voltage), and wide area overview displays." Specifying the state estimator as part of the Reliability Toolbox[55] clarifies current NERC reliability standards by indicating that the state

[55] See the Reliability Toolbox Rationale and Recommendation section.

estimator, as defined, is mandatory. It also clarifies the term "adequate analysis tools."

Recommendation – S11

Specify and measure minimum availability for state estimator, including a requirement for solution quality.

State Estimator Availability

If the state estimator is mandatory for bulk electric system situational awareness, it must be highly available and redundant. Awareness of state estimator availability is discussed in the recommendations in Section 5.4, Critical Applications Monitoring. However, a more detailed awareness (via a requirement for state estimator availability) of state estimator availability is necessary than what is described in Section 5.4; in particular, a metric measuring "adequate" availability should be established.

RTBPTF Recommendation

RTBPTF recommends adding the following new requirement to Standard TOP-006 to measure state estimator availability:

PR2. State Estimator Availability. Each reliability coordinator and transmission operator shall operate its state estimator based on the following metrics:

a. State Estimator Availability Metric 1 (SEA1): Each reliability coordinator and transmission operator shall operate such that its state estimator shall have at least one converged solution (i.e., produce a state-estimate solution) for at least 97.5 percent of 10-minute clock periods (i.e., six non-overlapping periods per hour) during a calendar month.

b. State Estimator Availability Metric 2 (SEA2): Each reliability coordinator and transmission operator shall also operate such that its state estimator shall have at least one converged solution (i.e., produce a state-estimate solution) for every continuous 30-minute interval during a calendar day.

RTBPTF recommends the following measures (see PM2a and PM2b) for the state estimator availability requirements stated above. To validate the effectiveness of the metrics, RTBPTF recommends that a pilot program (or field trial) be conducted to analyze the metrics' effectiveness.

PM3. Measures for State Estimator Availability

PM2.1. The responsible entity shall achieve, at a minimum, Requirement PR2a (SEA1) compliance of 97.5 percent. SEA1 is calculated by converting a state estimator availability ratio to a compliance percentage as follows:

$$SEA1 = \left[1 - \frac{V_{month}}{TP_{month}}\right] * 100$$

$$where:$$

$$V_{month} = \text{Violations per month}$$

$$TP_{month} = \text{Total Periods per month}$$

The violations per month are a count of the number of periods (10-minute clock periods) during which the state estimator does not have at least one converged solution. Each responsible entity shall report the total number of violations for the month.

PM2.2. The responsible entity shall achieve no SEA2 violations per day. One SEA2 violation equates to the state estimator not having at least one converged solution for a period of 30 contiguous minutes (three consecutive 10-minute clock periods), for example, if the state estimator is unavailable continuously for 40 minutes (no converged solution within four consecutive 10-minute clock periods), SEA2=1 for the calendar day or if the state estimator is unavailable continuously for 60 minutes (no converged solution within six consecutive 10-minute clock periods, SEA2=2 for the calendar day. For the purpose of simplicity, when the state estimator remains unavailable through midnight on any day (i.e., through a transition in calendar days), the SEA2 calculation shall be attributed to the previous calendar day. Each responsible entity shall report the total SEA2 violations per month.

Rationale

Recommended requirements PR2a and PR2b measure the availability of the state estimator solution for RCs and TOPs. PR2a is consistent with the NERC mandate for MISO to fully implement and test its state estimator and contingency analysis tools "to ensure they can operate reliably no less than every ten minutes."[56] Recommended requirement PR2b ensures that the state estimator is unavailable for no more than 30 minutes during a calendar day; this would prevent prolonged periods of unavailability that would negatively affect situational

[56] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 152.

awareness. RTBPTF believes that these availability requirements (SEA1 and SEA2) are consistent with the mandate that operators be aware of potential IROL/SOL violations and have 30 minutes to take the necessary actions to correct/prevent violations. Together with contingency analysis, the state estimator is a critical application that determines potential IROL/SOL violations.

RTBPTF believes that requiring RCs and TOPs to have an available state estimator solution at least once every 10 minutes 97.5 percent of the time will greatly enhance situational awareness. The feasibility of requirements SEA1 and SEA2 is based on the survey data regarding current state estimator availability. Survey data described earlier support the technical feasibility of the state estimator availability requirements as follows:

- The average wall clock (in seconds) execution time for state estimators is 28.9 seconds.
- The average trigger periodicity for state estimator is 319 seconds.
- The most common trigger periodicity for automatic triggers is 5 minutes.
- State estimator unavailability is less than 15 minutes 95.5 percent of the time.
- Eighty-eight percent (15 out of 17) of all survey respondents consider lapses in availability of 30 minutes or longer to significantly impact their operations.

RTBPTF believes that the recommended state estimator availability requirements are reasonable targets based on the survey results.

State Estimator Solution Quality

The state estimator must be highly available and must also be able to provide a reasonable, accurate, robust solution that fulfills the purposes for which it is intended.

RTBPTF Recommendation

RTBPTF recommends that a state estimator solution-quality requirement be established. However, RTBPTF had difficulty formulating specific, technically defensible state estimator solution-quality metrics. The Real-Time Tools Survey did not sufficiently address the issue of the current practices/methods in determining state estimator solution quality. Therefore, RTBPTF believes that state estimator solution-quality metrics warrant further investigation and development. RTBPTF recommends that the SAR process be initiated to define specific, technically defensible state estimator solution-quality metrics.

RTBPTF recommends adding the following new requirement in Standard TOP-006 in order to measure state estimator solution quality:

PR3. State Estimator Solution Quality. Each reliability coordinator and transmission operator shall operate such that its state estimator shall have sufficient solution quality for each converged case.

RTBPTF believes there is no single metric for state estimator solution quality. The survey revealed various methods for assessing state estimator solution quality but these methods were highly dependent on the type of state estimator algorithm being used. RTBPTF recommends that NERC (through the SAR process) develop and define state estimator solution-quality metrics. Pending this development, RTBPTF recommends a possible set of state estimator solution-quality metrics as operating guidelines until mandatory solution-quality metrics are established. Based on the Requirement PR3, RTBPTF recommends the following measure:

PM4. Each reliability coordinator and transmission operator shall have and provide upon request evidence of calculations that demonstrate state estimator solution quality for each converged case.

Rationale

RTBPTF recommends that state estimator availability requirements be augmented by solution-quality requirements to ensure that operators are provided with accurate information so they can be fully aware of the system situation at any given time. Requirement PR3 mandates that RCs and TOPs be cognizant of state estimator solution quality in tandem with complying with the state estimator availability requirement PR2.

Applicability Statement for Recommended Standards

RTBPTF recommends that all RCs and TOPs be required to have a state estimator for monitoring bulk electric system elements and critical reliability parameters as defined in the recommended additions or modifications to the NERC standards applicable to RCs and TOPs. Other responsible entities who use state estimators to support or complement their RCs' ability to operate the bulk electric system reliably in accordance with formal agreements, contracts, or established practices or procedures shall be subject to the same standards for the state estimator as their RCs.

Recommendations for New Operating Guidelines

The subsections below describe recommended guidelines for state estimator operation.

Recommendation – G4

Establish state estimator solution-quality metrics to ensure accurate data and other reliability analysis.

Operating Guidelines for State Estimator Solution Convergence Parameters

It is difficult to recommend specific state estimator voltage and angle convergence tolerances because of the different algorithms employed by different state estimators and the manner in which specific convergence parameters are used in these algorithms. For example, some state estimators check convergence based on changes of the absolute values of voltage magnitudes and voltage phase angles (relative to ground) between successive iterations. At least one vendor bases convergence on changes between successive iterations on voltage magnitude drops and angle differences across branches. There are other approaches as well. Table 2.5-47 summarizes the survey responses for internal and external system voltage and angle convergence tolerances.

Statistic	Internal Voltage Convergence Tolerance	Internal Angle Convergence Tolerance	External Voltage Convergence Tolerance	External Angle Convergence Tolerance
Average	0.0145	0.0143	0.0140	0.0127
Median	0.0065	0.0063	0.0080	0.0075
Max	0.1000	0.1000	0.1000	0.1000
Min	0.0001	0.0001	0.0001	0.0001
Std Dev	0.0269	0.0262	0.0230	0.0216
n	26	26	23	23

Table 2.5-47 — Internal and External System Voltage and Angle Tolerances

From the summary statistics in the table above, we see there is a wide range in survey responses (from 0.0001 to 0.1). However, a review of the individual responses (not shown) reveals that the overwhelming majority of voltage magnitude and voltage angle convergence tolerances are under 0.01 kV per unit and 0.01 radians, respectively. These values essentially represent a "lowest common denominator." The median responses are well under 0.01 kV per unit and 0.01 radians. Based on these observations, RTBPTF recommends that voltage magnitude and voltage angle convergence tolerances should be set to values no greater than the median values listed in Table 2.5-47. These are reasonable, achievable, and non-restrictive tolerances for most state estimator algorithms.

Operating Guidelines for State Estimator Solution-Quality Metrics

RTBPTF recommends that Operating Guidelines for state estimator solution-quality metrics be established that would apply until technically defensible metrics are developed. RCs need a high-quality estimation of the state of the bulk power system elements within their wide-area view to provide accurate data to other reliability analysis and market applications. Tools such as contingency analysis and power flow are highly dependent upon the state estimator's solution quality. For TOPs to maintain situational awareness of their "local" transmission systems, an accurate state estimator solution is required. An accurate solution is also necessary for other reliability analysis applications to determine the cause(s) of SOL violations. Table 2.5-3 details the applications that depend on the state estimator for the reliability coordinators and transmission operators. Table 2.5-48 lists the state estimator solution-quality metrics currently used by survey respondents.

What is Your Metric for Assessing the Accuracy of the Results of Your State Estimator Application? (Please check all that apply.)	**RC01**	**RC02**	**RC03**	**RC04**	**RC05**	**RC06**	**RC07**	**RC08**	**RC09**	**RC10**	**RC11**	**RC12**	**Other**	**Total**
Use cost index as a performance indicator	X	X	X	X			X				X	X	3	**10**
Use Chi-Squared criteria as performance indicator		X	X			X	X	X					3	**8**
Use measurement error/bias analysis as a performance indicator			X						X	X			4	**7**
Use average residual value as a performance indicator	X												1	**2**
Other(s)	X	X			X								3	**6**

Table 2.5-48 — State Estimator Solution-Quality (Accuracy) Metric

The quality of the state estimator solution should be measured using one or more of the metrics below; most of these recommended metrics are based on the survey results shown in Table 2.5-48 above. The reliability entity should track this set of metrics over time to gauge the pattern and determine what signals a problem with state estimator solution quality. Deviation from the "normal range" of these metrics should trigger state estimator maintenance and support. Even though no criteria for state estimator solution quality metrics are recommended at this time, these metrics are important because they could affect the contingency analysis solution.

The following metrics were not based on the survey results but rather on internal discussions within RTBPTF regarding recommending guidelines to the industry to assess state estimator solution quality.

1. *Cost Index*
   Cost index is also referred to as "Performance Index" or "Quadratic

Cost." In general, it measures the sum of the squares of the normalized estimate errors (residuals). Increasing cost index values could indicate deteriorating state estimator solution quality. See inset for a technical discussion.[57]

Technical Discussion of Cost Index

$$J(\hat{x}) = \sum_{j=1}^{m} \left[\frac{z_j - h_j(\hat{x})}{\sigma_j} \right]^2$$

where:

J is the "cost index" (sometimes called "performance index" or "quadratic cost")

m is the number of measurements being used in the estimate (excludes those that have been flagged bad and omitted)

z_j is the j^{th} measurement value (voltage, MW, Mvar, tap measurement, etc.)

$\hat{x}$ is a vector of estimated state variables (voltage magnitudes, voltage phase angles, etc.)

σ_j is the standard deviation of the metering error associated with measurement z_j (it is the inverse of the measurement weight)

$h_j(x)$ is a non-linear vector function that relates the state variable vector to measurement z_j.

The theoretical expected value of $J(\hat{x})$ is m-n where "m" is the number of measurements used in the estimate and "n" is the number of state variables. The theoretical variance of $J(\hat{x})$ is 2(m-n). Note that if the only state variables are voltage magnitudes and voltage phase angles, the value of n = 2b-1 where b is the number of electrical buses. The value of n will be greater if transformer taps and other quantities are used as state variables.

2. *Chi-squared Test*
The Chi-squared test is a statistical test against the cost index to determine the presence of measurements that are inconsistent with estimated values; these could be bad measurements, topology errors, etc. This test is often used as a trigger for anomaly detection processing. Tracking the number of anomalous measurements could aid entities in tracking state estimator solution quality over time. Increasing numbers of anomalous measurements could indicate deteriorating state estimator solution quality. See inset for a technical discussion.[58]

[57] Grainger, John J., and William D. Stevenson, Jr. 1996. *Power System Analysis*. McGraw-Hill, Inc.
[58] Ibid.

Technical Discussion of Chi-Squared Test

If one assumes that all of the measurements used by the state estimator have errors that are independent of each other, follow a normal distribution, each having a mean of zero, then the cost index, $J(\hat{x})$, follows a chi-squared distribution with m-n degrees of freedom (where "m" is the number of measurements and "n" is the number of state variables). Under these conditions, the expected value of $J(\hat{x})$ is equal to m-n, and the expected value of its variance is equal to 2(m-n). Tabulated values of chi-square ($\chi^2_{m-n,a}$) associated with a given number of degrees freedom (k=m-n) and probability (α) are available in statistical tables or can be computed from formulas. If the computed value of $J(\hat{x})$, where $\hat{x}$ is a vector of estimated state variables, is less than or equal to $\chi^2_{m-n,a}$, there is a (1-α)*100% probability that there are no bad input measurements, or conversely, a α*100% probability that there is at least one or more bad input measurements. Therefore, if $J(\hat{x}) \leq \chi^2_{m-n,a}$ then the estimated state variables are considered "good". If $J(\hat{x}) > \chi^2_{m-n,a}$ then there is at least once bad measurement in the input and error processing must be done to locate and remove the bad measurement(s) from the inputs. A common procedure for eliminating bad measurements using the chi-square test is as follows:

1. Use the raw measurements z_1, z_2, ..., z_m from the system to determine the least squares estimates of the state variables x, or $\hat{x}$.

2. Compute the estimated values of z, $\hat{z}$, from the estimated state variables using the relation $h(\hat{x})$.

3. Evaluate $J(\hat{x}) = \sum_{j=1}^{m} \left[\frac{z_j - h_j(\hat{x})}{\sigma_j} \right]^2$

4. For the appropriate number of degrees of freedom (m-n) and a user specified probability, α, determine whether or not $J(\hat{x}) \leq \chi^2_{m-n,a}$. If this is satisfied then the estimated state variables are accepted as being accurate and processing is done.

If $J(\hat{x}) > \chi^2_{m-n,a}$ then there is at least one suspect measurement in the measurement input. In this case use an algorithm)) to omit the "bad" measurements and then go back to step 1 above (i.e., remove the measurement(s) with the largest standardized error(s).

3. *Ranked Normalized Residual*s
   Normalized residuals are normalized individual estimate errors. Ranking normalized residuals in descending order aids entities in detecting causes of bad state estimator solutions based on specific measurements. Measurements that consistently rank high could indicate bad telemetry/measurement data.

4. *Maximum MW/Mvar Mismatch*
   The maximum MW/Mvar mismatch metric is applicable to state estimator algorithms that treat zero-injection buses (i.e., buses that do not have a load or generator connected to them) as high-confidence measurements. Macedo (2004)[59] says that state estimator MVA mismatch should be less than 10 MVA. Macedo does not distinguish between internal and external footprints; however, the survey results indicate some state estimators have the capability to track the maximum MW/Mvar mismatch on an internal and external basis. RTBPTF is not recommending specific values for internal/external MW/Mvar mismatch parameters. However, RTBPTF believes that where this capability exists, reliability entities should track both internal and external maximum MW/Mvar mismatch and observe trends over time. Sudden increases or an upward trend in maximum MW/Mvar mismatch could indicate deteriorating state estimator solution quality.

5. *Number of Iterations*
   Keeping track of the number of state estimator iterations over a period of time could provide information indicative of state estimator solution quality. The reliability entity should establish a normal range of state estimator iterations based on its model. If solution convergence exceeds these norms, state estimator results should be investigated.

6. *Major Topology Changes*
   Tools that keep track of major topology changes from one state estimator run to the other could help in tracing problems caused by changing topology of the network model.

[59] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

Factors Affecting State Estimator Solution-Quality Metrics

The values of the state estimator solution-quality metrics may depend upon many factors including:

1. **Modeling of electrical devices, connectivity, and mapping of telemetry data**. In state estimation, network topology is treated as given and assumed to be correct. If topology is incorrect, the state estimator may not converge or may yield grossly incorrect results. A topology error may stem either from:
   - Inaccurate status of breakers and switching devices, or
   - Errors in the network model.

   (Note that inaccuracies in the status of switching devices may be caused by a temporary or permanent loss of telemetry data)

2. **Availability and quality of telemetry data**. Telemetry data are essential components of the state-estimation process, as discussed extensively in Section 1.1,Telemetry Data, of this report.

3. **Inadequate Observability**. State estimation is extended to the unobservable parts of the network through the addition of pseudo-measurements. Pseudo-measurements are computed based on load prediction using load distribution factors, or they can represent non-telemetered generation assumed to operate at a base-case output level. The quality of pseudo-measurements may be questionable if they are not updated regularly to reflect current conditions. Note that when performing state estimation for the unobservable part of the network, it is possible to corrupt the states estimated from telemetry data.

4. **Measurement redundancy of the network**. This term is defined as the ratio of the number of measurements to the number of state variables in the observable area of the network.

Recommendation – A6

Identify minimum measurement observables, adequate redundancy, and critical measurements to improve state-estimator observability and solution quality.

Areas Requiring More Analysis

RTBPPTF recommends that the following areas be considered for further analysis. The Real-Time Tools Survey did not go in detail on these areas.

1. Minimum Measurement Observability
   The state estimator should be capable of monitoring the transmission network so that the estimator has sufficient measurements to calculate the voltage and angle at each bus. Without this minimum information, operators cannot know the real-time flows and expected post-contingency flows on the transmission system. Note that observability defines the percentage of the network meeting this minimum requirement. Current research and development in incorporating PMUs into the state estimator claims improved state estimator observability and solution quality.[60]

2. Inadequate Redundancy
   Redundant measurements are crucial for detecting and identifying bad data. Higher redundancy also ensures a more reliable state estimator solution in the face of a temporary loss of measurements. A bus measurement is observable if its state can be estimated using measured data without reliance upon pseudo-measurements, such as measurements from load or transformer tap models. Redundancy is a measure of the ability to maintain observability when access to telemetry data is lost. Critical measurements are those for which observability (in terms of the state estimator) will be lost if the measurement is lost. More investigation is needed for other appropriate measures such as the redundancy ratio (the total number of measurements divided by the total number of state variables) and the percent measurement of observable buses by kV level. The intent is to provide a state estimation driven by measurements as opposed to pseudo-measurements, which will minimize islands of poor measurement observability.

3. Critical Measurements
   The state estimator should be able to identify critical measurements in the system whose loss will result in either:
   - An inability to monitor a loading on a transmission element operated at high voltage and identified as critical to the system, or
   - An inability to monitor loading on a high-voltage autotransformer that is identified as critical to the system.

[60] See the following website: http://www.pserc.wisc.edu/ecow/get/generalinf/presentati/psercsemin1/2psercsemin/abur_pmu_pserc_teleseminar_nov2005_slides.pdf#search=%22zero%20injection%20bus%20state%20estimator%22.

Recommendation – A7

Establish a pilot program to collect data and build appropriate state estimator performance metrics.

Additionally, RTBPTF recommends establishing a pilot program of a few RCs/TOPs that represent the individual systems, to collect data that could be used to establish the appropriate performance metrics. The pilot program would:

1. Review the recommended standards and devise a test plan.
2. Test the recommended standards for availability.
3. Recommend changes or additions to the recommended standards for availability.
4. Identify metrics for solution quality (accuracy) that have global applicability.
5. Test the identified metrics for solution quality.
6. Recommend standards (if possible) for state estimator solution quality.

Examples of Excellence

RTBPTF cites the unique approach taken by MISO to ensure that its state estimator provides the information necessary for operators to maintain situational awareness as an example of excellence (See EOE-8 in Appendix E).

Section 2.6
Contingency Analysis

Definition

Contingency analysis is a computer application used to analyze the impact on power system security of specific, simulated outages (lines, generators, or other equipment) or higher load, flow, or generation levels. Contingency analysis identifies problems such as line overloads or voltage violations that will occur if a new system event (contingency) takes place. The state estimator solution represents current system conditions and usually serves as the base case for contingency analysis. The information a contingency analysis generates enables RCs and TOPs to implement mitigation plans in advance of a contingent event such as a line trip. Contingency analysis is used as a real-time application as well as for studying potential scenarios. This section discusses both types of contingency analysis.

Background

The NERC Steering Group *Technical Analysis of the August 14, 2003 Blackout*[61] concludes that a nonfunctional contingency analysis was a key cause of the blackout:

> Cause 1e: FE did not have an effective contingency analysis capability cycling periodically on-line and did not have a practice of running contingency analysis manually as an effective alternative for identifying contingency limit violations. Real-time contingency analysis, cycling automatically every 5–15 minutes, would have alerted the FE operators to degraded system conditions….

NERC reliability standards IRO-005 and TOP-004 require all RCs and TOPs to monitor post-contingency conditions of bulk electric system elements. Most commonly, a real-time contingency analysis application is used to monitor potential post-contingency voltage and thermal violations.

NERC Reliability Standard TPL-002, System Performance Following Loss of a Single Bulk Electric System Element, is a planning standard. It requires that a transmission system be planned so it can be operated reliably following a Category-B contingency. As defined in this same standard, a Category-B contingency is an event that results in the loss of a single element of the bulk electric system, such as s generator, transformer, or transmission circuit, due to a single-line ground or 3-phase fault with normal clearing or the loss of an

[61] Technical Analysis of the August 14, 2003, Blackout: *What Happened, Why, and What Did We Learn?* Report to the NERC Board of Trustees by the NERC Steering Group - July 13, 2004, page 96.

element without a fault. None of the operating standards, including the IRO and TOP series, contains an equivalent definition of a real-time contingency.

In a real-time operating environment, one or more elements are often out of service for maintenance or other reasons. Operators must be able to analyze and respond to any event that reasonably could cause the loss of an additional element, i.e., the next contingency. At a practical level, events that result in activation of protective relays are the most common causes of the next contingency. Consequently, real-time contingencies must be defined that accurately reproduce the results of activating protective relays, which are intended to remove elements from service to minimize damage or stop the spread of undesirable system conditions. Because more than one element is sometimes removed, it is insufficient to define a real-time contingency as a single element. A contingency must be defined as the set of circuit breakers or other automatic devices designed to clear a fault or otherwise respond to activation of protective relays that remove an element from service.

RTBPTF considers contingency analysis an essential tool for enabling operators to monitor and maintain the reliability of the bulk electric system. Macedo (2004)[62] states that real-time contingency analysis is a minimum requirement for network analysis tools for grid reliability and implies that operators should perform contingency analysis at least every 5 minutes on all facilities that operate at or above 100 kV within the RC area and on critical external facilities. RTBPTF agrees with Macedo's assessment that contingency analysis is a minimum requirement but does not agree that it must be performed every 5 minutes. In lieu of requiring a specific interval of execution, RTBPTF recommends requiring that contingency analysis solutions be produced within a reasonable interval in order to detect potential SOL/IROL violations. RTBPTF believes that the accuracy of contingency analysis solutions over time provides a quantifiable measure of the application's overall performance.

This Contingency Analysis section of the Real-Time Tools Survey examines the applications that RCs, TOPs, and BAs use to analyze the effects of contingent events. RTBPTF classifies real-time contingency analysis as a critical real-time tool.

Summary of Findings

All RCs and most other respondents to the contingency analysis section of the survey have a functional contingency analysis application, and most consider it an essential tool for system reliability. This section describes what respondents report about their contingency analysis applications, how they are integrated with other systems and alarms, and how the applications and their various features

[62] Macedo, Frank. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14. Available at: http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

are valued. Because RTBPTF finds contingency analysis to be an essential tool for monitoring the elements of the bulk electric system, RTBPTF recommends that all RCs and TOPs be required to have contingency analysis for their areas of operation and that reliability parameters be established for the applications. Survey results reveal the need to establish requirements for the quality of solutions derived from contingency analysis. Survey results also reveal the need to establish criteria for identifying which internal and external facilities should be included in the set of contingent elements to be analyzed.

Prevalence of Applications

All 17 RCs and approximately 54 percent of all other respondents (15 out of 28) have a functional contingency analysis application. Of the 13 respondents who have no such application, 8 plan to add one. Tables 2.6-1 and 2.6-2 summarize the reported prevalence of contingency analysis applications. RC responses are noted separately.

Do You Have Contingency Analysis?	RCs	Others	Total
Yes	17	15	**32**
No	0	13	**13**
Total	**17**	**28**	**45**

Table 2.6-1 — Prevalence of Contingency Analysis

Is Your Contingency Analysis Operational?	RCs	Others	Total
Yes	17	14	**31**
No	0	1	**1**
Total	**17**	**15**	**32**

Table 2.6-2 — Prevalence of Operational Applications

The 1 respondent who reports a non-operational contingency analysis application indicates there are plans to make it operational.

Perceived Value of Contingency Analysis Application

Most respondents perceive that contingency analysis is the most critical tool for secure system operation and is ”essential” for operating the system reliably after a disturbance. Table 2.6-3 summarizes the values respondents assign to contingency analysis.

How Valuable is Contingency Analysis?	RCs	Others	Total
Is contingency analysis essential?	16	13	**29**
Is contingency analysis desirable?	1	1	**2**
Is contingency analysis of minimal value?	0	0	**0**
Is contingency analysis of no value?	0	0	**0**
Total	**17**	**14**	**31**

Table 2.6-3 — Perceived Value of Contingency Analysis

Characteristics of Applications

Respondents were asked to describe the general characteristics of their contingency analysis applications. The questions in this section of the survey cover the integration of contingency analysis within EMSs, interfaces between contingency analysis and the state estimator, and algorithms used in the applications. Table 2.6-4 summarizes respondents' reported customization of contingency analysis applications. Table 2.6-5 describes the integration of contingency analysis with EMS systems. Table 2.6-6 describes the algorithms used in respondents' contingency analysis applications.

Degree of Contingency Analysis Customization	RCs	Others	Total
Off-the-shelf with some customization	9	6	**15**
Off-the-shelf	5	5	**10**
Highly customized	3	3	**6**
Total	**17**	**14**	**31**

Table 2.6-4 — Customization of Applications

Degree of Contingency Analysis Integration	RC	Other	Total
Fully integrated with production SCADA/EMS system	16	14	**30**
Interfaced to SCADA/EMS system	1	0	**1**
Stand-alone	0	0	**0**
Total	**17**	**14**	**31**

Table 2.6-5 — Integration of Contingency Analysis

Table 2.6-5 indicates that the contingency analysis applications of 97 percent of all respondents (30 out of 31) are integrated fully with their EMS systems. This result highlights the prevalence of contingency analysis as a real-time application.

Contingency Analysis Algorithm	RCs	Others	Total
Full AC	9	8	**17**
Decoupled	8	4	**12**
Other	0	2	**2**
Total	**17**	**14**	**31**

Table 2.6-6 — Contingency Analysis Algorithms

All respondents indicate that their contingency analysis uses the state estimator solution as a base case, which again implies the widespread use of contingency analysis as a real-time tool for predicting post-contingency system conditions.

Modeling Power Controls

Respondents were asked how their applications, when simulating contingencies, model power controls, both reactive (transformer taps, generators, and capacitors) and active (loads, generators, and phase shifters). Table 2.6-7 summarizes the modeling of internal load tap changer (LTC) taps during contingency analysis. Table 2.6-8 summarizes the modeling of shunt-series reactive devices during simulations.

Modeling LTC Taps in Contingency Analysis (Internal)	RCs	Others	Total
Locked globally	11	5	**16**
Can be moved for specific contingencies	1	4	**5**
Can be moved for specific LTCs	2	0	**2**
Globally free to move	1	3	**4**
Other(s)	2	2	**4**
Total	**17**	**14**	**31**

Table 2.6-7 — LTC Modeling in Contingency Analysis

Modeling Shunt/Series Reactive Devices in Contingency Analysis (Internal)	RC	Other	Total
Locked globally (reactive device status unchanged based on input)	9	6	**15**
Status can be switched in/out for specific contingencies	2	2	**4**
Status can be switched in/out for specific reactive devices	4	3	**7**
Globally free to change status switched in/out	1	2	**3**
Other(s)	1	0	**1**
Total	**17**	**14**	**31**

Table 2.6-8 — Modeling Shunt/Series Devices

Although no respondents report that they relax generator Mvar limits when modeling specific contingencies, 14 percent (4 out of 29) relax them for specific generators. Regarding active power controls, only 33 percent of respondents (10 out of 30) have applications that incorporate load change-over capability (the capability to transfer lost load to other specific loads). Seventy-three percent of respondents (22 out of 30), however, indicate that their applications can reallocate lost load and generation using generation participation factors. Tables 2.6-9 and 2.6-10 summarize capabilities related to active power control.

Do You Have Automatic Load Change-Over Capability?	RCs	Others	Total
Yes	6	4	**10**
No	10	10	**20**
Total	**16**	**14**	**30**

Table 2.6-9 — Automatic Load Change-Over Capability

Do You Reallocate Lost Generation and Load Using Generator Participation Factors?	RC	Other	Total
Yes	11	11	**22**
No	5	3	**8**
Total	**16**	**14**	**30**

Table 2.6-10 — Reallocation of Generation and Load

Most respondents (22 out of 30) reallocate lost generation and load using a single set of generation participation factors.

Actions Indicated by Applications

Respondents report that they model various remedial control actions in their contingency analysis applications. Most survey participants model LTCs, shunt reactive devices, and generators as remedial controls; however, 1 respondent uses RASs that require rigorous modeling. Table 2.6-11 summarizes the inclusion of post-contingency manual actions in contingency definitions. Table 2.6-12 summarizes the various remedial controls that respondents model.

Do You Consider Post-Contingency Manual Actions in Contingency Definitions?	RC	Other	Total
Yes	3	5	**8**
No	14	9	**23**
Total	**17**	**14**	**31**

Table 2.6-11 — Inclusion of Post-contingency Manual Actions

Controls Used for Remedial Action	RCs	Others	Total
Shunt reactive devices	9	3	**12**
Series reactive devices	3	1	**4**
Load tap changers	5	3	**8**
Phase shifters	2	1	**3**
Generator voltages	5	4	**9**
Under-voltage load shedding	2	2	**4**
Generation re-dispatch	4	4	**8**
Generation shedding	4	4	**8**
Bus and branch sectionalizing	3	1	**4**
Other(s)	1	0	**1**
No remedial action	5	4	**9**
Total	**16**	**10**	**26**

Table 2.6-12 — Remedial Controls in Contingency Analysis

Defining Contingencies

Contingencies can be defined based on the voltage levels of the elements involved. The minimum voltage level for elements included in contingency analysis usually depends on the structure of the region's transmission system. Survey respondents were asked what minimum voltage level they use in modeling contingencies. Fifty-three percent of all respondents (15 out of 28) monitor internal facilities having voltages less than 69 kV, and 82 percent (23 out of 28) monitor internal facilities having voltages less than 115 kV. These data indicate that most entities monitor lower-voltage facilities.

Responses indicate that RCs designate an average minimum voltage level of 105 kV although 1 RC models only those contingent elements that exceed 315 kV. Figure 2.6-1 shows the distribution of minimum kV levels of contingent elements that RCs and other respondents model.

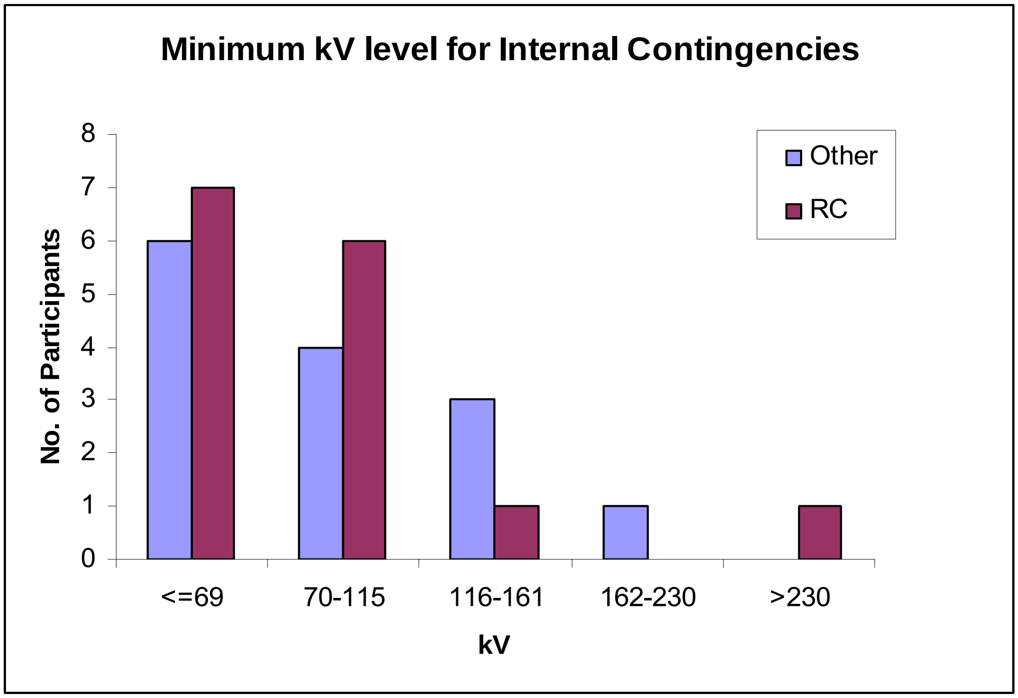

Figure 2.6-1 — Minimum kV Level for Modeled Contingencies

Figure 2.6-1 shows that 45 percent of respondents (13 out of 29) model contingencies that are less than 69 kV, and 35 percent (10 out of 29) model contingencies that have a minimum voltage between 70 and 115 kV. These data indicate that most entities consider the effects of outages of low-voltage transmission system elements although the practice varies greatly by region.

Seventy percent of all respondents (21 out of 30) define as contingencies all or most internal facilities that exceed the designated minimum kV levels. Only 23 percent of respondents (7 out of 30), however, define as contingencies all or most external facilities that affect internal systems. Table 2.6-13 summarizes reported practices regarding defining internal and external contingencies.

What Describes Your Contingency Definitions above Minimum kV Level?	RCs	Others	Total
All/most internal facilities are defined	10	11	**21**
Only select/critical internal facilities are defined	6	3	**9**
All/most external facilities that impact internal system are defined	7	0	**7**
Only select/critical external facilities that impact internal system are defined	4	9	**13**
No external contingencies are defined	5	5	**10**
Total	**16**	**14**	**30**

Table 2.6-13 — Contingency Definitions

An unexpectedly high 33 percent of respondents (10 out of 30) define no external contingencies. This result indicates a need to establish requirements for defining both external contingencies that affect internal systems and internal contingencies that could affect neighboring systems. This issue is addressed in the Recommendations for New Reliability Standards section below.

Survey responses define a range of transmission elements as contingencies. Exactly 60 percent of respondents (18 out of 30) categorize both circuit breakers and other transmission equipment as contingencies. Table 2.6-14 summarizes the elements respondents define as contingencies.

What Do You Define as Contingencies?	RC	Other	Total
Individual circuit breakers	9	10	**19**
Transmission lines	16	13	**29**
Transformers	16	12	**28**
Generating units	14	11	**25**
Bus faults	5	4	**9**
Phase-shifters (Phase angle regulators)	7	3	**10**
Loads	6	3	**9**
Shunt capacitors/reactors	5	1	**6**
Static var compensators	2	0	**2**
FACTS devices	0	0	**0**
DC lines (pole failures)	3	2	**5**
Multiple lines (on shared structure or right-of-way)	11	4	**15**
Other(s)	1	1	**2**
Total	**16**	**14**	**30**

Table 2.6-14 — Contingency Elements

Based on Table 2.6-14, contingencies most commonly comprise transmission lines and transformers. Individual circuit breakers also may be included in modeling contingencies, depending on the system configuration.

The total number of contingencies each respondent defines ranges from 30 to 10,000, as shown in Table 2.6-15. Figure 2.6-2 shows the ratio of total contingencies defined to the number of transmission lines and transformers each respondent models.[63]

Respondent	Total Contingencies	Respondent	Total Contingencies
R01	30	R17	900
R02	50	R18	973
R03	70	R19	1,000
R04	106	R20	1,000
R05	118	R21	1,500
R06	300	R22	1,500
R07	300	R23	1,800
R08	358	R24	3,000
R09	400	R25	3,500
R10	400	R26	4,340
R11	550	R27	10,000
R12	568	Average	1,324
R13	600	Median	800
R14	800	Minimum	30
R15	800	Maximum	10,000
R16	800		

Table 2.6-15 — Number of Contingencies Defined

[63] Aliases are used for responses from RCs and TOPs to mask respondents' names. The aliases in this table are not necessarily consistent with those used in similar tables or figures in this report. That is, "R01" in any given table or figure is not the same as "R01" or the equivalent identifier in another table or figure in this report.

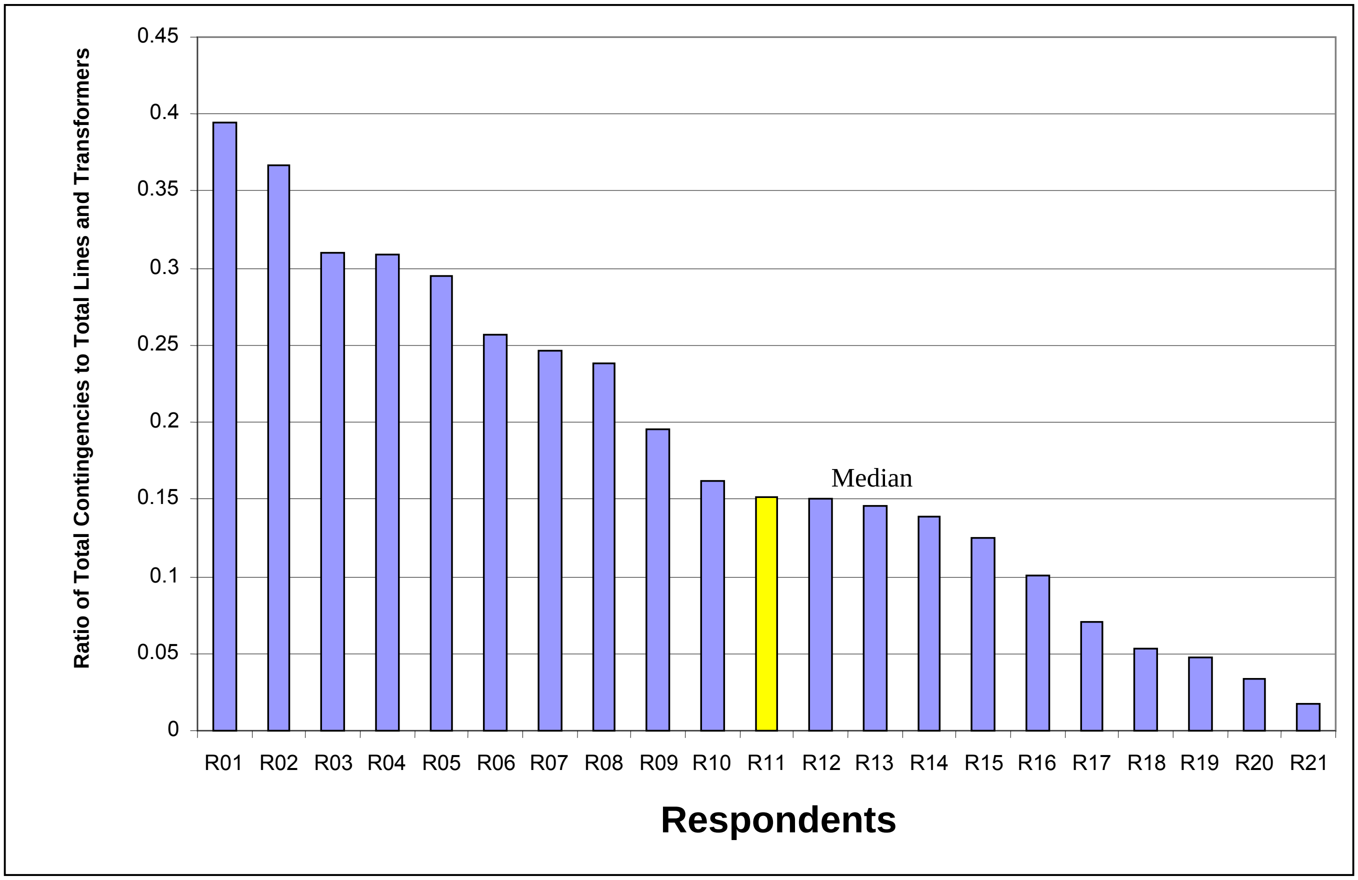

Figure 2.6-2 — Ratio of Total Contingencies to Total Branches and Transformers

Monitoring Limit Violations

The primary purpose of contingency analysis is to identify limit violations on monitored transmission system elements resulting from the post-contingency effects of the outages of transmission system elements modeled as contingent elements. Most RCs, TOPs, and BAs monitor selected elements, ignoring violations on any elements they do not monitor. Monitored elements are classified primarily by kV level. The minimum kV level for which internal system monitoring is applied is 24 kV. Figure 2.6-3 summarizes the minimum kV levels of transmission system elements that RCs and others monitor.

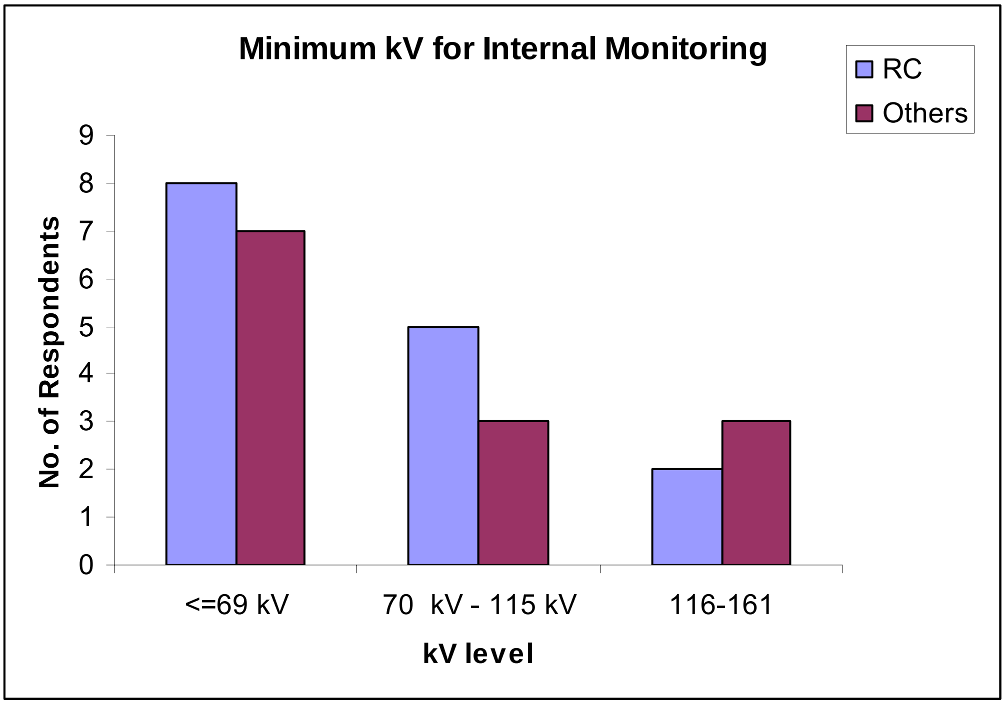

Figure 2.6.3 — Minimum kV Level Monitored

Figure 2.6-3 shows that 53 percent of all respondents (15 out of 28) monitor internal facilities having voltages less than 69 kV, and 82 percent (23 out of 28) monitor those having voltages less than 115 kV. These data indicate that most entities monitor lower-voltage facilities above their specified minimum kV level. However, few respondents also monitor all or most external facilities that affect their own system. Table 2.6-16 summarizes respondents' approaches to monitoring internal and external facilities.

What Best Describes Your Internal and External Monitored Facilities?	RCs	Others	Total
All/most internal facilities are monitored	13	11	**24**
Only selected/critical internal facilities are monitored	2	3	**5**
Total	14	15	**29**
All/most external facilities that impact internal system are monitored	7	0	**7**
Only selected/critical external facilities that impact internal system are monitored	6	8	**14**
No external facilities are monitored	3	6	**9**
Total	**16**	**14**	**30**

Table 2.6-16 — Internal and External Facilities Monitored

Only 23 percent of respondents (7 out of 30) monitor all relevant external facilities, and 30 percent (9 out of 30) monitor none. The data in Table 2.6-16 highlight the lack of wide-area monitoring.

As shown in Table 2.6-17, the total number of facilities each respondent monitors ranges from 35 to 10,000. The number of facilities monitored depends on the size of the network model used in the contingency analysis application.

Respondent	Total Monitored Facilities	Respondent	Total Monitored Facilities
R01	10,000	R13	750
R02	9,243	R14	500
R03	8,000	R15	500
R04	7,000	R16	487
R05	5,000	R17	254
R06	4,000	R18	212
R07	3,000	R19	118
R08	2,700	R20	35
R09	2,400	Average	2,946
R10	1,800	Median	1,675
R11	1,550	Minimum	35
R12	1,371	Maximum	10,000

Table 2.6-17 — Total Number of Facilities Monitored

Signaling Violations

Most respondents indicate that they can monitor thermal, low-voltage, and high-voltage violations; some (53 percent) can also monitor violations in bus voltage drop. Approximately 73 percent of all respondents employ some sort of alarm signal to alert them to contingency violations. Table 2.6-18 describes respondents' practices for signaling contingency violations.

Which Best Describes How You Alarm Violations?	RCs	Others	Total
General alarms — details viewed on contingency analysis displays	4	5	**9**
Detailed alarms — include details of facility, contingency, and violations	7	6	**13**
Others	1	0	**1**
No alarms — violations viewed on contingency analysis displays	4	3	**7**
Total	**16**	**14**	**30**

Table 2.6-18 — Signaling Contingency Violations

Contingency analysis applications typically can identify unsolved or diverged contingencies. Such contingencies are of special concern because they can indicate impending reliability problems. Sixty percent of respondents (18 out of 30) indicate that an alarm is used to signal unsolved contingencies. Only 38 percent (11 out of 29), however, state that their operators have tools or procedures to detect whether a failed contingency indicates a potential voltage collapse.

Contingency analysis also can warn operators of impending violations. Table 2.6-19 summarizes the methods respondents report using to warn operators of impending violations.

Which best Describes How Operators Are Notified of Approaching Violations?	RCs	Others	Total
Warning prior to actual violation level	10	10	**20**
No warning prior to actual violation level	5	3	**8**
Others	1	1	**2**
Total	**16**	**14**	**30**

Table 2.6-19 — Signaling Impending Violations

Approximately 70 percent of respondents (14 out of 20) indicate that operators can select the level at which an alarm will alert them of impending violations.

Application Features

Respondents were asked to describe the features of their contingency analysis applications. A key feature is how the application presents its results to system operators. Because there may be numerous defined contingencies (depending on system size), it is important that violations be categorized. Seventy-one percent of total respondents (22 out of 31) indicate that their application has a feature for categorizing violations, and all of them make use of this feature. Seventy-three percent of RCs (11 out of 15) and 68 percent of all respondents (15 out of 22) consider this feature "essential." Table 2.6-20 summarizes the criteria used to categorize violations.

What Criteria Could the Operator Use/Apply to Automatically Sort Violations?	RCs	Others	Total
Violations sorted by type	12	4	**16**
Violations sorted by severity	14	6	**20**
Violations sorted by ownership and/or geographic area	5	1	**6**
Violations sorted by contingency	7	3	**10**
As needed	1	1	**2**
Other(s)	3	1	**4**
Total	**16**	**6**	**22**

Table 2.6-20 — Criteria for Categorizing Violations

Survey respondents also were asked how violations are presented to operators. Tables 2.6-21 and 2.6-22 show the prevalence of color coding and/or graphical displays as techniques for visualization of violations.

Are Violations Color-Coded?	RCs	Others	Total
Yes	7	2	**9**
No	9	4	**13**
Total	**16**	**6**	**22**

Table 2.6-21 — Are Violations Color Coded?

Do You Have the Ability to View Graphical Displays to Determine Violation Severity?	RCs	Others	Total
Yes	8	1	**9**
No	8	5	**13**
Total	**16**	**6**	**22**

Table 2.6-22 — Can Violations Be Viewed Graphically?

Contingency analysis applications can be used to perform theoretical or study analyses of potential problems. The study analysis usually establishes a power-flow case representing anticipated future conditions (i.e., the time of today's forecasted peak load) and then performs "what-if" studies upon this base case (i.e., what if any defined contingency occurred during peak load conditions). All respondents report that their contingency analysis application has a study feature and that they use this feature. Table 2.6-23 summarizes respondents' perceived value of the study feature.

How do You Rank the Value of Study Contingency Analysis to Situational Awareness?	RCs	Others	Total
Essential	14	12	**26**
Desirable	3	2	**5**
Minimal	0	0	**0**
No value	0	0	**0**
Total	**17**	**14**	**31**

Table 2.6-23 — Perceived Value of Study Contingency Analysis

An important feature of contingency analysis applications is the ability to group and prioritize contingencies and monitored elements. This feature enables operators to easily enable/disable monitoring of sets of monitored elements and activate/deactivate sets of contingencies that have common features (i.e., that are at the same kV level) without having to control each one individually. Eighty-one percent of all respondents (25 out of 31) report having features that group and prioritize contingencies and monitored elements, and 45 percent (10 out of 22) consider those features "essential."

Respondents were asked whether their applications are able to identify the worst (most harmful) contingency impacting each monitored facility. Responses are presented in Table 2.6-24. Approximately half of all respondents consider this feature "essential."

Do You Have the Ability to Automatically Detect the Worst Contingency for Each Monitored Facility?	RCs	Others	Total
Yes	10	6	**16**
No	7	8	**15**
Total	**17**	**14**	**31**

Table 2.6-24 — Automatically Detecting the Worst Contingency

Some contingency analysis applications can calculate distribution factors (line outage distribution factors, generation shift factors, etc.) that can be used to identify remedial control actions such as re-configuration and re-dispatch or to trigger operating guides to help with resolving potential violations of operating limits. The contingency analysis applications of only 23 percent of respondents (7 out of 31) contain this feature.

Rate of Execution

Most respondents rely on periodic triggers to initiate a contingency analysis. The rate at which contingency analyses are executed ranges from once every minute to once every 30 minutes, with an average of once every 8 minutes reported by RCs and once every 13 minutes reported by TOPs. Figure 2.6-4 shows the rate at which RCs and others execute contingency analyses.

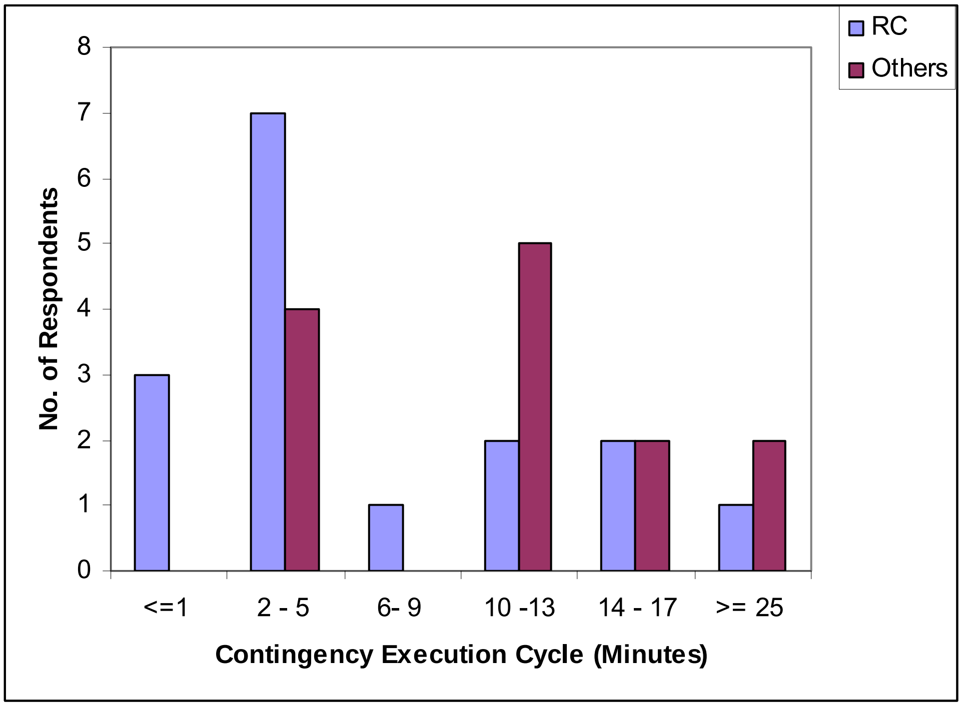

Figure 2.6-4 — Execution Rate for Contingency Analysis

The most common execution frequency is every 5 minutes. Some respondents use a manual trigger or disturbance triggers to augment routine periodic execution. The maximum time required for any RCs contingency analysis to execute is 4 minutes, with an average execution time of less than 1.5 minutes.

Availability of Contingency Analysis Application

The availability of the contingency analysis application is generally measured by how often it produces a successful solution for a given number of executions. Only 27 percent of respondents (8 out of 30) have historical data on contingency solutions or metrics for measuring their application's robustness. Table 2.6-25 summarizes the value respondents assign to being able to measure the availability of their contingency analysis applications.

How Would You Rank the Value of Having Capabilities in Contingency Analysis to Provide Availability Data?	RCs	Others	Total
Desirable	5	7	**12**
Minimal	5	3	**8**
None	1	1	**2**
Total	**11**	**11**	**22**

Table 2.6-25 — Perceived Value of Availability Data

A rather high 36 percent of respondents (8 out of 22) consider the ability to collect reliability data in contingency analysis to be of minimal value. In contrast, all who have tools to measure availability are using them. Respondents were asked approximately how often and how long their contingency analysis application is unavailable (the frequency distribution of down time). Of the 6 respondents who answered this question, most note that their answers rely on estimates rather than historical data. Five of those 6 respondents indicate that, of all the times that contingency analysis becomes unavailable, it is unavailable for less than 15 minutes for at least 95 percent of those times. Four of those respondents report that it is never unavailable for longer than 15 minutes.

Support for Applications

Because most respondents consider contingency analysis critical to real-time operation of their system, they understand the need to monitor the application's availability and functionality. Approximately 61 percent of respondents (19 out of 31) report having tools or procedures for monitoring the status of their contingency analysis application and making support personnel aware when it is unavailable or functioning incorrectly. Table 2.6-26 summarizes the availability of tools and procedures for monitoring the status of the contingency analysis application. Table 2.6-27 summarizes the perceived value of those tools and procedures.

Do You Have Tools or Procedures to Monitor the Status of Your Contingency Analysis?	RCs	Others	Total
Yes	12	7	**19**
No	5	7	**12**
Total	**17**	**14**	**31**

Table 2.6-26 —Tools/Procedures to Monitor Contingency Analysis Application's Status

How Would You Rank the Value of Having Tools to Monitor the Status of Your Contingency Analysis?	RCs	Others	Total
Desirable	4	7	**11**
Minimal	1	0	**1**
None	0	0	**0**
Total	**5**	**7**	**12**

Table 2.6-27 — Perceived Value of Monitoring Tools for Contingency Analysis Status

Approximately 94 percent of all respondents (17 out of 18), including all responding RCs, say that their contingency analysis is monitored continuously 24 hours per day, 365 days per year.

Recommendations for New Reliability Standards

The results of the Real-Time Tools Survey detailed in the previous section support the assertion of Macedo (2004)[64] that contingency analysis is a minimum requirement -- i.e., an essential tool for operators.

Recommendation – S1

Mandate the following reliability tools as mandatory monitoring and analysis tools

- Alarm Tools
- Telemetry Data Systems
- Network Topology Processor
- State Estimator
- Contingency Analysis

Contingency Analysis: Mandatory Monitoring and Analysis Tool

The survey results indicate that contingency analysis applications are inherently delivered as part of commercially available modern SCADA/EMS systems. RTBPTF considers contingency analysis an essential tool for enabling operators to monitor and maintain the reliability of the bulk electric system. Because contingency analysis is required for maintaining an “n-1” secure bulk power transmission system, RTBPTF places it in the Reliability Toolbox among the mandatory monitoring and analysis tools[65]. Existing NERC reliability standards implicitly assume the use of contingency analysis to aid RCs and TOPs in maintaining situational awareness for the bulk electricity system. Standard IRO-

[64] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

[65] See the Reliability Toolbox Rationale and Recommendation section.

002 (Requirement R7) states "[e]ach Reliability Coordinator shall have ***adequate analysis tools*** [emphasis added] such as state estimation, ***pre and post-contingency analysis*** [emphasis added] capabilities (thermal, stability, and voltage), and wide area overview displays." Specifying that contingency analysis as part of the mandatory Reliability Toolbox clarifies that, under current NERC reliability standards, contingency analysis, as defined, is required. It also clarifies the term "adequate analysis tools."

Availability of Contingency Analysis Application

Given that contingency analysis is deemed a mandatory tool for maintaining situational awareness of the bulk electric system, it must be highly available and redundant. The availability of the contingency analysis application is discussed in the recommendations for Section 5.4, Critical Applications Monitoring. However, RTBPTF believes that a more complete understanding than that described in Section 5.4 is necessary. In particular, a metric for measuring adequate availability should be established.

Recommendation – S12

Specify and measure minimum availability for contingency analysis, including a requirement for solution quality.

RTBPTF Recommendation

RTBPTF developed the following proposed requirement (PR) for Standard TOP-006 in order to specify a minimum availability for contingency analysis.

PR1. Availability of Contingency Analysis

PR1.1 Real-Time Contingency Analysis Availability Metric 1 (RTCAA1): Each Reliability Coordinator and Transmission Operator shall ensure that its real-time Contingency Analysis produces at least one converged base-case solution and processes all defined contingencies for at least 97.5 percent of all10-minute clock periods (6 non-overlapping periods per hour) during each calendar month.

PR1.2 Real-Time Contingency Analysis Availability Metric 2 (RTCAA2): Each Reliability Coordinator and Transmission Operator shall also ensure that its real-time Contingency Analysis produces at least one converged base-case solution and processes all defined contingencies for every continuous 30-minute interval during a calendar day.

RTBPTF developed the following proposed measures (PMs) for the requirements given above. RTBPTF recommends that a pilot program (or field trial) be conducted to validate the effectiveness of the following PMs.

PM1. Measures for Availability of Contingency Analysis

PM1.1 Each Reliability Coordinator and Transmission Operator shall achieve, as a minimum, Requirement PR1.1 (RTCAA1) compliance of 97.5 percent. RTCAA1 is calculated by converting a Contingency Analysis availability ratio to a compliance percentage, as follows:

$$RTCAA1 = \left[1 - \frac{V_{month}}{TP_{month}}\right] * 100$$

$$where:$$

$$V_{month} = \text{Violations per month}$$

$$TP_{month} = \text{Total Periods per month}$$

The violations per month represent the number of 10-minute clock periods during which real-time Contingency Analysis did not produce at least one viable solution (one converged base-case solution and all defined contingencies processed).

PM1.2 Each Reliability Coordinator and Transmission Operator shall allow no RTCAA2 violations. One RTCAA2 violation equates to the real-time Contingency Analysis failing to produce at least one viable solution (one converged base-case solution and all defined contingencies processed) within any continuous 30-minute interval during a calendar day (three consecutive 10-minute clock periods). For example, if the real-time Contingency Analysis is unavailable continuously for 40 minutes (no viable solution within four consecutive 10-minute clock periods), RTCAA2 = 1 for the calendar day. If real-time contingency analysis is unavailable continuously for 60 minutes (no viable solution within six consecutive 10-minute clock periods), RTCAA2 = 2 for the calendar day. For simplicity, when the real-time Contingency Analysis is unavailable during a period that spans midnight, the RTCAA2 calculation shall be attributed to the preceding calendar day.

Rationale

Contingency analysis is a critical application for identifying potential IROL/SOL violations. Recommended requirement PR1.1 is consistent with the NERC mandate that MISO fully implement and test its state estimator and contingency analysis tools “to ensure they can operate reliably no less than every ten minutes.”[66] Proposed requirement PR1.2 specifies that the real-time contingency analysis must be unavailable for no more than 30 minutes during a calendar day so that situational awareness is not compromised**.**

RTBPTF believes that these proposed availability requirements are consistent with requirements that operators remain aware of potential IROL/SOL violations and take the actions necessary to alleviate violations as soon as possible but always within 30 minutes. In addition, these recommended metrics are consistent, performance based, and, based on survey findings, technically feasible.

Quality of Solutions

Contingency analysis solves a single power-flow problem for each defined contingency. If the power-flow solution for a particular contingency fails to converge, it could mean that a reliability problem such as a voltage collapse might occur if the contingent event actually happened. In contrast, failure of a contingency to solve could indicate that a modeling error or other problem is degrading the quality of the base case and thus the results for all contingencies, even those that solve successfully. It is important to examine unsolved or diverged contingencies to assess whether the power-flow failure may indicate an impending problem. The survey indicates that 60 percent of all respondents consider failed contingencies important enough that audible alarms bring the failures to the operators’ attention. RTBPTF shares this concern and believes that failed (unsolved) contingencies represent a key indicator of the quality of contingency analysis solutions.

RTBPTF Recommendations

RTBPTF developed the following proposed requirements (PRs) for Standard TOP-006 to ensure the quality of contingency analysis solutions.

PR2. Quality of Contingency Analysis Solutions

PR2.1 Each Reliability Coordinator and Transmission Operator shall have documented procedures for investigating and resolving the failure of a contingency to solve.

PR2.2 Each Reliability Coordinator and Transmission Operator shall have processes for recording (logging) all contingencies that fail

[66] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 152.

to solve. Each log entry shall include a contingency identifier and the date/time of the solution failure.

PR2.3 Each Reliability Coordinator and Transmission Operator shall document the actions taken to resolve a failed contingency.

To validate the effectiveness of these requirements, RTBPTF proposes that they be included in the pilot program (or field trial) previously recommended for the availability metrics. RTBPTF developed the following proposed measures (PMs) for the requirements given directly above.

PM2. Measures for Quality of Contingency Analysis Solutions

PM2.1 Each Reliability Coordinator and Transmission Operator shall demonstrate that operators have ready access to current, approved procedures for investigating contingency failures.

PM2.2 Each Reliability Coordinator and Transmission Operator shall provide, if requested, hard copies of contingency failure logs for specified time periods.

PM2.3 Each Reliability Coordinator and Transmission Operator shall provide, if requested, records of the actions taken to resolve specified failed contingencies.

Rationale

Failure of a contingency to solve can indicate a poor-quality base-case solution or a problem with the system state such as a voltage collapse. In either case, situational awareness of potential IROL or SOL violations is compromised until personnel can identify and resolve the cause of the failed contingency. Enacted along with the recommended availability metrics, the above recommendations will provide that this critical real-time tool receives the attention and maintenance required to consistently produce solutions of sufficient quality for its intended purpose.

Criteria for Defining Contingency

The primary function of contingency analysis is to provide an early indication of an impending limit violation resulting from the outage of a transmission element. Thus, criteria are needed to identify which elements of the bulk electric system must be defined as contingencies. Requirement R1 of Standard IRO-003-1 states:

> Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as

> necessary to ensure that, ***at any time, regardless of prior planned or unplanned events*** [emphasis added], the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.

This requirement provides the criteria that define which facilities are to be monitored within the RC's area, but does not specify that RCs are to define all those facilities as contingencies. The emphasized words imply, however, that all possible contingent events must be analyzed in real time in order to maintain, under any possible topological configuration, the capability to identify potential IROL and SOL violations.

Real-time contingencies must be defined that accurately reproduce the results of activated protective relays, which are installed to remove elements from service to minimize damage or stop the spread of undesirable system conditions. Because in some cases more than one element may be removed, it is insufficient to define a real-time contingency as only a single element. A contingency must be defined as the set of circuit breakers or other automatic devices that operate to clear a fault or otherwise respond to protective relay actions intended to remove an element from service.[67]

Consider, for example, two transmission lines connected in a breaker-and-a-half scheme,[68] as shown in Figure 2.6-6. If the breaker between line B and bus 2 were open for maintenance, a fault on line A would trip the remaining two breakers, thereby removing both line A and B from service. If the contingency for the loss of line A was defined simply as the loss of line A, and not the tripping of the breakers connecting the line to the grid, then a real-time contingency analysis would not evaluate the true result of the event.

[67] RTBPTF is not recommending that contingencies be defined that represent relay mis-operations or over-trips.

[68] A breaker-and-a-half bus scheme is a "method of interconnecting several circuits and breakers in a switchyard so that three circuit breakers can provide dual switching to each of two circuits by having the circuits share one of the breakers, thus a breaker and one-half per circuit; this scheme provides reliability and operating flexibility." From the Bonneville Power Administration web site: http://www.bpa.gov/corporate/pubs/definitions/b.cfm - busscheme

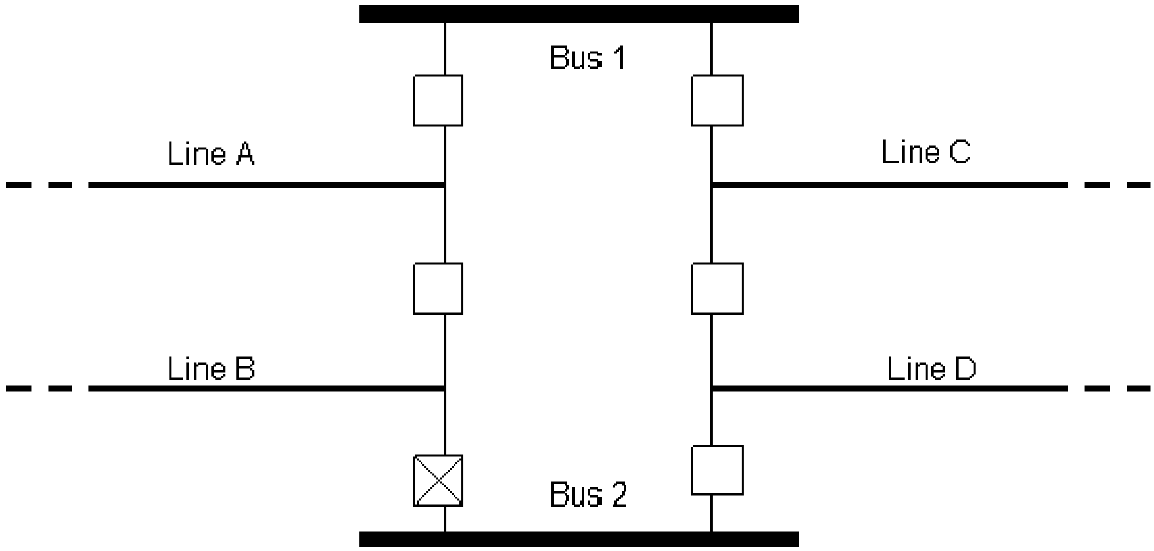

Figure 2.6-6 — Breaker-and-a-Half Scheme

Recommendation – S13

Specify criteria and develop measures for defining contingencies.

RTBPTF Recommendation

RTBPTF developed the following proposed requirements (PRs) for Standard TOP-006 to specify the criteria for defining contingencies that must be analyzed in real time.

PR3. Criteria for Defining Contingencies

PR3.1 Each Reliability Coordinator and Transmission Operator shall define as a contingency to be analyzed in real time each element of the Bulk Electric System[69] within its area of responsibility.

PR3.2 Each Reliability Coordinator and Transmission Operator shall define as contingencies to be analyzed in real time all critical Bulk Electric System elements in adjacent areas that, if taken out of service ***at any time, regardless of prior planned or unplanned events,*** could cause an IROL or SOL violation.

PR3.3 Each contingency must be defined to include the set of circuit breakers or other automatic devices designed to clear a fault or

[69] This recommendation assumes a rational and comprehensive definition of the bulk electric system. See the discussion of the bulk electric system in the Introduction of this report.

otherwise operate in response to activation of protective relays to remove the Bulk Electric System element from service.

RTBPTF developed the following proposed measures (PMs) for the requirements given directly above.

PM3. Measures for Defining Contingency

PM3.1 Each Reliability Coordinator and Transmission Operator shall have a list of the contingencies in its area of responsibility that are analyzed in real-time Contingency Analysis and shall document the criteria used to define as contingencies Bulk Electric System elements in its area of responsibility.

PM3.2 Each Reliability Coordinator and Transmission Operator shall have a list of contingencies in adjacent areas that are analyzed in real-time Contingency Analysis and shall document the criteria used to define as contingencies Bulk Electric System elements in adjacent areas.

PM3.3 Upon request, each Reliability Coordinator and Transmission Operator shall demonstrate for a randomly designated set of contingencies how the contingency definitions accurately simulate the results of a protective relay being activated.

Rationale

The recommended requirement that RCs and TOPs define as contingencies all bulk electric system elements in their areas of responsibility is based on RTBPTF's interpretation of requirement R1 of Standard IRO-003. If impact-based reliability criteria are used to identify bulk electric system elements, then by definition each of those elements potentially can impact reliability. If "bright-line" criteria such as voltage or MW levels are used to identify bulk electric system elements, such criteria are proxies for impact-based criteria, and the bulk electric system elements so identified also, by definition, have potential impacts on reliability. Either way, each bulk electric system element must be defined as a contingency, and the potential impact of each bulk electric system element must be analyzed in real-time contingency analysis.

As discussed above for the breaker-and-a-half scheme, contingencies must be defined in sufficient detail so that the most realistic scenarios are analyzed, thus providing operators with the most realistic system impacts. Events that activate protective relays are the most common causes of the next contingency. To assess the full effects of a contingency, the contingency definition must include the specific devices that operate in response to activation of the protective relay that removes a bulk electric system element from service.

Applicability Statement for Recommended Standards

RTBPTF recommends that all RCs and TOPs be required to have contingency analysis for monitoring all elements of their bulk electric system, as detailed in the recommended additions or modifications to NERC standards. Other responsible entities who use contingency analysis to support or complement their RCs' ability to operate the bulk electric system in accordance with formal agreements, contracts, or established practices shall be subject to the same standards for contingency analysis as their reliability coordinators.

Recommendation – G5

Identify only existing controls modeled in contingency analysis and develop conservative contingency screening criteria.

Recommendations for New Operating Guidelines

RTBPTF developed the following proposed operating guidelines to support the recommended requirements and measures presented above.

- RCs and TOPs should confirm that their contingency analysis models only the controls that exist in the field. For example, contingency analysis should not be configured to change the modeled tap positions of fixed tap transformers during the analysis in order to solve a contingency or eliminate limit violations. If a control is automatic (i.e., its activation does not require operator intervention), it can be modeled in contingency analysis. Manually activated controls either should not be modeled, or, if they are modeled, results should be presented both with and without the controls. The rationale for this guideline is that if a control must be manually activated, the operator must be notified of the potential contingency that requires activating that control.
- If contingencies are screened before inclusion in analysis, RCs should apply conservative screening criteria, so that potentially harmful contingencies are not misidentified as harmless.

Areas Requiring More Analysis

RTBPTF is not recommending additional areas for analysis related to Contingency Analysis.

Examples of Excellence

The transmission network (grid) is the power source for the offsite power system. The trip of a nuclear power plant itself can affect the grid and result in a loss of offsite power (LOOP). The most common occurrence is reduction in plant's switchyard voltage as a result of loss of the nuclear plant. The low voltage at the plant can activate the voltage-protection system and remove the plant safety bus from offsite power. A real-time contingency analysis application can be used to simulate such conditions and alert plant operators in advance.

In addition, a generic letter from Nuclear Regulatory Commission (NRC) recommends usage of real-time contingency analysis to determine the grid conditions that would make the Nuclear Power Plant offsite power system inoperable in the event of various contingencies.[70] During the August 14, 2003 northeast blackout nine nuclear power plants tripped and eight of these lost offsite power. The length of offsite power unavailability ranged from 1 hour to six and one-half hours. Although nuclear power plants are designed to cope with a LOOP event through the use of onsite power supplies, LOOP events are considered precursors to station blackout. An increase in the frequency or duration of LOOP events increases the probability of core damage.

RTBPTF cites the use of real-time contingency analysis by Entergy Corporation to accurately simulate the effects of loss of nuclear power plant on switchyard voltage as an example of excellence (See EOE-9 in Appendix E).

[70] Federal Register / Vol. 70, No. 69 / Tuesday, April 12, 2005 / Notices

Section 2.7
Critical Facility Loading Assessment

Definition

A critical facility loading assessment (CFLA) employs a computer application to evaluate a set of contingencies or other events that could affect reliability of the bulk electric system or one of its elements and then approximates the resultant post-contingency impacts for a pre-determined set of monitored elements. CFLA, which typically uses telemetered SCADA flows and line outage distribution factors (LODFs), represents an approximate, backup technique for obtaining a solution to contingency analysis if the primary state estimator and/or contingency analysis applications are unavailable.

Background

Macedo (2004)[71] cites use of CFLA as a best practice.

Summary of Findings

The CFLA section of the survey asks about use of CFLA applications for monitoring network conditions. Few Real-Time Tools Survey respondents report having a functional CFLA application. The applications that are in use appear to have wide ranges of capabilities and sophistication.

Of the 42 respondents to the CFLA question in the survey, only 4 RCs and 3 TOPs report having an application for performing CFLA. One RC gives no response. One RC that does not have CFLA ability plans to acquire the tool. Three TOPs also indicate they plan to acquire CFLA. Despite the low number of those who use CFLA, 6 out of the 7 respondents who have this application (all 4 RCs and 2 TOPs) rate it "essential" for situational awareness.

Features and Functions

Most of the respondents who report having CFLA use highly customized applications provided by their EMS vendors. Only 1 RC reports having developed an in-house CFLA application. All CFLA applications are either integrated or interfaced with the SCADA or the EMS; none operate in a stand-alone mode. Respondents' descriptions of their CFLA applications are presented in Table 2.7-1.

[71] Macedo, Frank. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14. Available at: http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

NOTE: In the columns of the following table, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, “6/7 = 86%” means that 6 out of a total of 7 respondents, or 86% of respondents, gave the indicated response.

Which Best Describes Your CFLA?	All	RCs
Highly customized	6/7 = 86%	3/4 = 75%
Off-the-shelf with some customization	1/7 = 14%	1/4 = 25%
Off-the-shelf	0/7 = 0%	0/4 = 0%
Supplied by SCADA/EMS vendor	3/7 = 43%	3/4 = 75%
Supplied by other vendor	0/7 = 0%	0/4 = 0%
Developed in-house	4/7 = 57%	1/4 = 25%
Fully integrated with SCADA/EMS system	6/7 = 86%	3/4 = 75%
Interfaced to SCADA/EMS system	1/7 = 14%	1/4 = 25%
Stand-alone	0/7 = 0%	0/4 = 0%
Triggered periodically	5/7 = 71%	2/4 = 50%

Table 2.7-1 — Descriptions of CFLA Applications

Among the 4 RCs who have CFLA, only 2 have applications that can define contingencies in true topographical terms of breakers and equipment. The other applications define contingencies in terms of equipment only. All CFLA applications can define branch contingencies, and 3 out of 4 can also define generator contingencies. One RC reports that its application also defines unit and other types of contingencies.

CFLA software packages differ significantly in terms of sophistication. Some use externally calculated LODFs and/or generator shift factors to distribute SCADA flows or injections from contingent branches or generators to monitored branches. Such applications contain no internal topology processor. The CFLA applications that incorporate topology processors can provide more accurate results. Some respondents claim their applications are capable of approximating true post-contingency apparent power (MVA) loading, but most approximate only the resultant real power (MW) loading.

The applications of all 4 reliability coordinators who have CFLA incorporate the same ratings from SCADA as the primary contingency analysis uses. Three of the CFLA applications can monitor branches or multiple branch sets. These 3 can, at a minimum, also define the critical internal and external facilities that affect loads on internal system facilities.

Three of the applications run by RCs contain either general or detailed alarms for alerting users to violations, which can be categorized by severity. All 4 reliability coordinators consider this feature either “desirable” or “essential.”

Users

Respondents report that the system operators and control room staff are the primary users of CFLA applications.

Performance, Monitoring, and Availability

The rates at which CFLA applications execute vary. One RC's application executes on a 1-minute cycle while another's executes on a 4-second cycle, and those of the other 2 execute in response to changes in SCADA status data. The application of 1 TOP executes every 10 minutes, that of another every 30 seconds, and the last every 4 seconds. One RC says the program runs "full-time"; another indicates that the results from CFLA trigger other programs.

Survey results reveal that no RC has developed a metric for CFLA availability. Only 1 RC indicates that such a metric would be desirable.

Support for Application

Only 2 RCs monitor the availability of their CFLA applications continuously and notify on-call or dedicated support staff of any application failures.

Recommendations for New Reliability Standards

Based on results from the very few who responded to this section of the survey, RTBPTF does not recommend creating or modifying reliability standards or operating guidelines to incorporate tools for performing critical facility loading assessment. RTBPTF, however, recommends performing additional analysis of CFLA and similar approximate techniques to assess their value in providing a contingency solution if contingency analysis and/or state estimator applications are unavailable

Recommendations for New Operating Guidelines

RTBPTF does not recommend the development of new operating guidelines for Critical Facility Loading Limits.

Recommendation – A8

Evaluate capability of critical facility loading assessment application in providing a backup solution if contingency analysis or the state estimator is unavailable.

Areas Requiring More Analysis

RTBPTF recommends that CFLA and similar approximate techniques be evaluated for their value for providing backup solutions in the event that the state estimator or conventional contingency analysis applications become unavailable. For CFLA to serve in this manner as a useful backup tool, the anomalies that can cause contingency analysis to fail should not be a cause for CFLA to fail as well. The capability of CFLA to enhance the wide-area view and assist in providing security of the bulk electric system should be analyzed further, and the capabilities that are crucial to making CFLA a valuable tool should be identified and communicated to software providers. Improvements should also be made to include breaker-oriented topology along with equipment outages in CFLA contingency definitions in order to improve the accuracy of the estimation.

Examples of Excellence

RTBPTF cites the use of a Thermal Tracking CFLA by PJM to screen for transfer interface violations and a number of potentially serious double-contingency violations as an example of excellence (See EOE-10 in Appendix E).

Section 2.8
Power Flow

Definition

Power flow is a computer application used to calculate the state of the electric power system based on load, generation, net interchange, and facility status data. Power flow calculates the system state in the form of flows, voltages, and angles. Power flows are available in both online and offline versions.

An application that evaluates online power flow is typically incorporated into an EMS (or has a direct data feed from an EMS) and utilizes node-breaker topology, whereas offline power flow utilizes models of bus branches and static data. This section of the report pertains only to online power flow, which hereafter is referred to simply as "power flow."

Background

EMSs utilize various applications to monitor and analyze the condition of a power system. Applications such as the state estimator and contingency analysis are intended to run automatically at given intervals to provide operators with real-time situational awareness. Applications such as power flow and study contingency analysis, on the other hand, are used to assess system conditions for the next hour or day. Power flow also is used in "n-1" contingency analysis to simulate the effect of the next worst contingency. In addition, it is used to identify potential voltage collapse or reliability problems.

The *NERC Blackout Report* identified inadequate hour-ahead and day-ahead studies. The following excerpts from the document emphasize the importance of look-ahead analysis.[72]

> FirstEnergy did not perform adequate hour-ahead operations planning studies after Eastlake 5 tripped off-line at 13:31 to ensure that FirstEnergy could maintain a 30-minute response capability for the next contingency. The FirstEnergy system was not within single contingency limits from 15:06 to16:06. In addition to day-ahead planning, the system should have been restudied after the forced outage of Eastlake 5.
>
> FirstEnergy did not perform adequate day-ahead operations planning studies to ensure that FirstEnergy had adequate resources to return the system to within contingency limits following the possible loss of their largest unit, Perry 1. After Eastlake 4 was forced out on August 13, the

[72] North American Electric Reliability Corporation. 2004. *August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts.* February 10. p. 100.

operational plan was not modified for the possible loss of the largest generating unit, Perry 1.

The *NERC Blackout Report* implies that, if FirstEnergy had employed look-ahead studies using tools such as power flow, the cascading condition that caused the blackout of August 14, 2003, might have been avoided.

Summary of Findings

This section of the report examines how survey respondents, involved in operating transmission systems, operate, maintain, and utilize power-flow applications and discusses key issues faced by those who use power flow.

Power-flow applications, which are important for monitoring system reliability, appear to be used widely to simulate system conditions and to troubleshoot EMS problems. Routinely using them to perform look-ahead studies would further enhance operators' situational awareness.

The survey reveals a lack of systematic procedures for analyzing a failed power flow solution that could indicate potential voltage collapse. RTBPTF concludes that tools should be developed to warn operators of a failed solution or potential problems.

Prevalence and Perceived Value of Power Flow

There were 45 unique respondents to this section of the survey, including all 17 of the RCs surveyed. Table 2.8-1 shows that 71 percent of all respondents (32 out of 45) and 94 percent of reliability coordinators (16 out of 17) report having a power flow application. Most respondents (90 percent, or 28 out of 31) consider the application "essential" for situational awareness; a few (10 percent, 3 out of 31) consider it "desirable"; no respondents consider it to be of minimal or no value. Table 2.8-1 summarizes responses to general questions concerning power-flow applications.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, "32/38=84%" means that 32 out of a total of 38 respondents, or 84% out of respondents, gave the indicated response.

Question	All	RCs	Others
Do you have on-line power flow?	32/45=71%	16/17=94%	14/26=54%
If you do not have on-line power flow, do you plan to add it in the future?	7/13=54%	0/1=0%	7/12=58%
Is your on-line power flow operational?	31/32=97%	16/16=100%	13/14=93%
Do you rate your power flow "essential" as a reliability tool for situational awareness?	28/31=90%	13/16=81%	13/13=100%
Do you rate your power flow "desirable" as a reliability tool for situational awareness?	3/31=10%	3/16=19%	0/15=0%
Do you rate your power flow as of "minimal value" as a reliability tool for situational awareness?	0/31=0%	0/16=0%	0/15=0%
Do you rate your power flow as of "no value" as a reliability tool for situational awareness?	0/31=0%	0/16=0%	0/13=0%

Table 2.8-1 — Prevalence and Perceived Value of Power Flow

Application Interfaces and Features

Table 2.8-2 summarizes the characteristics of respondents' power-flow applications, and shows that all respondents report that their power-flow applications are integrated fully with their SCADA and EMS systems. In addition, EMS vendors appear to offer power flow as a standard product.

Power-Flow Application Characteristics	All	RCs	Others
Power flow fully integrated with production SCADA/EMS	30/30=100%	15/15=100%	13/13=100%
Power flow fully integrated with non-production SCADA/EMS	0/30=0%	0/15=0%	0/13=0%
Power flow supplied by SCADA/EMS vendor	30/31=97%	15/16=94%	13/13=100%
Power flow supplied by other vendor	1/31=3%	1/16=6%	0/13=0%
Power flow developed in-house	0/31=0%	0/16=0%	0/13=0%

Table 2.8-2 — Characteristics of Applications

Both operators and operations support staff use power flow applications. Eighty-one percent of all respondents (25 out of 31) report that operators or control room staff are the primary users of the applications; approximately 48 percent (15 out of 31) indicate that operations support staff also use the applications (see Table 2.8-3). These numbers indicate that power-flow applications are used widely as a tool to simulate system conditions and to troubleshoot EMS problems.

Users	All	RCs	Others
System operators and/or other control room staff	25/31=81%	12/16=75%	11/13=85%
Operations support staff	15/31=48%	7/16=44%	7/13=54%
Supervisory and/or management staff	4/31=13%	0/16=0%	4/15=27%

Table 2.8-3 — Primary Users

The survey also asked what applications are interfaced with power flow, and what is the source of the base case provided to initialize the power-flow application.

Table 2.8-4 summarizes the responses.

Application	All	RCs	Others
SCADA	17/31=55%	8/16=50%	9/15=60%
Alarm tools	6/31=19%	2/16=13%	4/15=27%
Monitoring and visualization techniques	18/31=58%	9/16=56%	9/15=60%
Network topology processor	15/31=48%	10/16=63%	5/15=33%
State estimator	28/31=90%	14/16=88%	14/15=93%
Contingency analysis	26/31=84%	14/16=88%	12/15=80%
Critical facility loading assessment	1/31=3%	1/16=6%	0/15=0%
Study real-time maintenance	7/31=23%	3/16=18%	4/15=27%
Study network topology processor	19/31=61%	10/16=63%	9/15=60%
Study contingency analysis	30/31=97%	16/16=100%	14/15=93%
Study critical facility loading assessment	1/31=3%	1/16=6%	0/15=0%

Table 2.8-4 — Applications Interfaced with Power Flow

Table 2.8-4 indicates that power-flow applications are interfaced primarily with the state estimator (90 percent, or 28 out of 31), contingency analysis (84 percent, or 26 out of 31), and study contingency analysis (97 percent, or 30 out of 31). Data from
Table 2.8-4 suggest that power-flow applications also are used frequently to provide a base case that is used in other applications, such as study contingency analysis or visualization techniques.

Table 2.8-5 and Table 2.8-6 summarize other characteristics of power-flow applications. Industry members most commonly use a full AC algorithm. The slack bus chosen varies evenly between single unit/bus or distributed generation slack. Full survey results for power flow are provided in Appendix D, which summarizes results not detailed in this Summary of Findings.

What Algorithm Does Your Power Flow Typically Use?	All	RCs	Others
Full AC	21/31=68%	12/16=75%	9/15=60%
Decoupled	9/31=29%	3/16=19%	6/15=40%
Other	1/31=3%	1/16=6%	0/15=0%

Table 2.8-5 — Power-Flow Algorithms

What Type of Slack Does Your Power Flow Typically Use?	All	RCs	Others
Single unit or load bus	15/31=48%	7/16=44%	8/15=53%
Distributed generation	12/31=39%	7/16=44%	5/15=33%
Distributed load	3/31=10%	1/16=6%	2/15=13%

Table 2.8-6 — Power-Flow Slack Bus

Although most respondents use their power-flow application to monitor the entire internal system for thermal and voltage violations, NERC reliability Principle 7 emphasizes the need for wide-area monitoring. As illustrated in Table 2.8-7, only 42 percent of respondents (13 out of 31) monitor selected external facilities that affect their internal systems, and 29 percent of respondents (9 out of 31) monitor no external facilities at all. Therefore, RTBPTF believes that standards for monitoring external facilities need to be developed. For more details, see Section 4.2, Modeling Practices and Tools.

External System Monitoring	All	RCs	Others
All/most external facilities impacting internal system are monitored	9/31=29%	7/16=44%	2/13=16%
Only select external facilities impacting internal system are monitored	13/31=42%	6/16=37%	6/13=46%
No external facilities are monitored	9/31=29%	3/16=19%	5/13=38%

Table 2.8-7 — External System Monitoring Using Power Flow

Verifying Accuracy

Survey results reveal that respondents use various methods to verify the accuracy of power-flow solutions. As illustrated in Table 2.8-8, for example, 61 percent (19 out of 31) of respondents use real-time applications (i.e., telemetry data system, alarm tools, state estimator, or contingency analysis) or other power-flow applications (i.e., offline power flow) to verify results of online power flow.

If a Power-Flow Solution is Questionable, How Do You Verify the Accuracy of the Solution?	All	RCs	Others
Compare results with distribution factors	4/31=13%	4/16=25%	0/13=0%
Compare results with another power-flow application	19/31=61%	9/16=56%	8/13=62%
Compare results with results from another case	17/31=55%	9/16=56%	6/13=46%
Compare results with another TOP's results	10/31=32%	6/16=38%	4/13=31%
Compare results with another study application's results	11/31=35%	7/16=44%	4/13=31%
Compare results with another real-time application's results	19/31=61%	12/16=75%	6/13=46%

Table 2.8-8 — Methods for Verifying Power-Flow Results

The importance of power-flow applications to reliability and the variety of methods used to verify results indicate a need to develop documented procedures for verifying the accuracy of results. The procedures should reflect the purpose for which the online power flow application is being used. For example, if power flow provides the base case for contingency analysis in a real-time system, results should be verified using real-time applications or SCADA.

A few respondents (20 percent, or 6 out of 30) indicate that they have tools/procedures to evaluate whether a non-converged power-flow solution indicates a possible voltage collapse. RCs (19 percent, or 3 out of 16) report a similar dearth of tools/procedures for identifying a potential voltage collapse indicated by a failed power-flow solution. Additionally, only 29 percent of all respondents (9 out of 31) report having procedures to detect and notify staff members of failed power-flow solutions. RTBPTF believes that tools should be developed to warn operators of a failed solution and indicate potential problems.

Power Flow in Look-Ahead Studies

Most respondents use power-flow applications to perform look-ahead studies. As shown in Table 2.8-9, eighty percent of all respondents report using power flow to perform hour-ahead to day-ahead analyses. Most users perform these studies on an as-needed basis, as shown in Table 2.8-10.

For Which Time Frames Do You Normally Perform Look-Ahead Power-Flow Studies?	All	RCs	Others
Look-ahead studies for less than 1 hour ahead	14/30=47%	7/16=44%	6/12=50%
Look-ahead studies from 1 hour to 1 day ahead	24/30=80%	11/16=69%	11/12=92%
Look-ahead studies for more than 1 day ahead	18/30=60%	7/16=44%	9/12=75%

Table 2.8-9 — Power Flow in Look-Ahead Studies

At What Periodicity Do You Normally Perform Look-Ahead Power-Flow Studies?	All	RCs	Others
Hourly	4/30=13%	4/16=25%	0/14=0%
Several times per day	5/30=17%	3/16=19%	2/14=14%
Daily	13/30=43%	6/16=38%	7/14=50%
As Needed	25/30=83%	11/16=69%	14/14=100%

Table 2.8-10 — Frequency of Look-Ahead Studies

Finally, the survey indicates that most respondents (46 out of 59) have a user interface to monitor power-flow data and results. Seventy percent of respondents (10 out of 13) who do not have an interface consider one "desirable."

Recommendations for New Reliability Standards

Given the need to support NERC reliability principles, and based on the inconsistencies identified in the Summary of Findings, RTBPTF recommends the following modifications to reliability standards.

Look-Ahead Analysis Requirement

Standard TOP-002 (Normal Operations Planning) and Standard IRO-004 (Reliability Coordination — Operations Planning) require reliability entities to perform day-ahead studies. Requirement R11 of TOP-002 states:

> [T]he Transmission Operator shall perform seasonal, next-day, and current-day bulk electric system studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these bulk electric system studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

The Purpose Statement for Standard IRO-004 says,

> [E]ach Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.

The requirement listed in IRO-004 and TOP-002 primarily focuses on day-ahead analysis and does not specify any requirements for hour-ahead analysis. To mitigate approaching SOL and IROL violations it is necessary to perform hour-ahead studies along with day-ahead and seasonal studies.

Recommendation – S14

Perform one-hour-ahead power-flow simulations to assess approaching SOL and IROL violations and corresponding measures.

RTBPTF Recommendation

To assess approaching SOL and IROL violations, RTBPTF recommends modifying TOP-002 and IRO-004 to include the following requirement:

> PR1: Each Reliability Coordinator and Transmission Operator shall, at a minimum, perform one-hour-ahead Power-Flow simulations during the following:
> - Occurrence of critical system event
> - Extreme load conditions
> - Large power transactions
> - Major planned outages

Fore the above requirement, RTBPTF recommends the following measure:

> PM1: Documented evidence showing results of hour-ahead studies and mitigation plans if needed must be kept by Reliability Coordinators and Transmission Operators.

Rationale

This recommendation addresses the following deficiency identified in the Blackout Report:

> FE did not perform adequate hour-ahead operations planning studies after Eastlake 5 tripped off-line at 13:31 to ensure that FE could maintain a 30-minute response capability for the next contingency. The FE system was not within single contingency limits from 15:06 to 16:06. In addition to day-ahead planning, the system should have been restudied after the forced outage of Eastlake 5.

The survey reveals that performing look-ahead studies is a prevailing practice. Forty-seven percent of all respondents perform look-ahead studies for less than 1 hour ahead, and 80 percent (24 out of 30 perform studies from 1 hour to 1 day ahead (see Table 2.8-9). An overwhelming 83 percent (25 out of 30) indicate that studies are done as needed (see Table 2.8-10).

The practice/process of performing look-ahead analysis during a major system event or when the power system is a stressed state suggests that reliability entities need to be more prepared. Systems are designed to withstand n-1 contingencies when they occur. However, changing conditions (e.g., scheduled system configuration, generation dispatch, interchange scheduling, and demand pattern changes) over the hour-ahead timeframe may need operator action in anticipation of these changing conditions. Performing look-ahead studies enhances operator situational awareness.

Recommendation – G6

Perform one-hour ahead contingency analysis to identify potential post-contingent problems approaching in next hour.

Recommendations for New Operating Guidelines

RTBPTF has recommended minimum standards for look-ahead analysis by listing events when one-hour-ahead analysis must be done. As an operating guideline and best practice, RTBPTF recommends performing a contingency analysis simulation using the one-hour-ahead power-flow base case every hour, employing an automatic method. This will identify potential post-contingent problems approaching in next hour.

Recommendation – A9

Verify accuracy of one-hour power-flow and contingency analysis results and ability to detect a potential voltage collapse revealed by a failed power-flow solution.

Areas Requiring More Analysis

RTBPTF identified the following two areas that require additional analysis:

Verification of Accuracy

The survey reveals that respondents use various methods to verify the accuracy of power-flow solutions. The methods and tolerances used in verifying results may depend on the purpose of the simulation. For example, an RC running power flow to simulate real-time conditions should verify the accuracy of results by comparing voltages, angles, and flows with those derived from state estimator. Because RTBPTF recognizes the need to further analyze and establish methods for verifying power-flow results, the task force recommends performing a detailed survey to identify current practices, which in turn could lead to developing standards or guidelines related to methods for verifying power-flow results.

Detection of Voltage Collapse

The survey reveals a lack of systematic procedures and tools for analyzing a failed power-flow solution that could indicate potential voltage collapse. RTBPTF suggests additional review and analysis of existing methods, tools, and algorithms for identifying a potential voltage collapse revealed by a failed power-flow solution.

Examples of Excellence

RTBPTF did not identify any Examples of Excellence related to Power Flow.

Section 2.9
Study Real-Time Maintenance

Definition

Study real-time maintenance (SRTM) is a study function that simulates real-time network applications (i.e. NTP, state estimator, contingency analysis etc.) and debugs problems without affecting the operation of the real-time applications. An SRTM tool can be an online application integrated with the production EMS system, an application integrated with a non-production EMS system [i.e. development, test, dispatcher training simulator (DTS) system etc.], or an offline application. (Note: Any reference to DTS is in the context of application maintenance, not training, which is not in RTBPTF's scope.)

Background

Given the complexity of the applications that make up EMS networks as well as their interaction with the telemetry, network model and actual power system, support staff must be able to quickly and easily recreate, debug, and resolve problems without affecting the real-time applications themselves. Without this capability, critical real-time network applications for monitoring and maintaining system reliability might be unavailable for extended periods.

Diminished situational awareness, attributable to the lack of availability of critical real-time network applications, contributed to the blackout of August 14, 2003. The causal analysis described in the *Outage Task Force Final Blackout Report*[73] reveals that the contingency analysis application in FE's control center was unavailable, and the state estimator and contingency analysis applications in the MISO control center were unavailable for some periods. Recommendation 37 in the *Outage Task Force Final Blackout Report* calls on entities to "[i]mprove IT forensic and diagnostic capabilities."[74] The report states that "[control areas] and [reliability coordinators] should seek to improve internal forensic and diagnostic capabilities, ensure that IT support personnel who support EMS automation systems are familiar with the systems' design and implementation, and make certain that IT support personnel who support EMS automation systems are trained in using appropriate tools for diagnostic and forensic analysis and remediation." RTBPTF believes that SRTM qualifies as a tool for performing diagnostic and forensic analysis and remediation of state estimator and contingency analysis applications, and that it is most effectively implemented independently, without hindering the real-time application it is analyzing.

Details in the *Outage Task Force Final Blackout Report* indicate that FE's contingency analysis application did not function properly and was not

[73] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. pp. 17–22
[74] Ibid. p. 166

maintained adequately. FE operators reported on-going problems with results from their real-time contingency analysis beginning when the application was installed in 1995. In addition, the application was not run in real-time mode. RTBPTF believes that if FE had adequate, trained, and experienced support staff who properly implemented their contingency analysis and routinely used an SRTM application to debug it and resolve problems, many of the causes of the August 14, 2003, blackout could have been avoided.

Based on details in the *Outage Task Force Final Blackout Report*, MISO support staff had a standard procedure for debugging real-time state estimator solutions by disabling the automatic triggers that normally would initiate real-time state estimator and contingency analysis. This practice resulted in periods when the applications were unnecessarily unavailable. Again, RTBPTF believes that if MISO had used an SRTM application to debug state estimator solutions, applications would have remained continuously available.

The SRTM section of the report summarizes reported use of and practices surrounding the SRTM (or equivalent) application.

Summary of Findings

This section of the report summarizes reported use of and practices surrounding the SRTM (or equivalent) application.

Real-Time Tools Survey results show that most RCs have, successfully use, and highly value SRTM. A total of 45 respondents answered the questions in the SRTM section of the survey. For respondents who perform multiple roles, each role is counted in the totals. Sixteen RCs responded, 25 TOPS responded uniquely (i.e., those that do not play any other role); and 2 balancing authorities (BAs) responded uniquely. Because so few BAs responded, the discussion in this section is based on results from RCs and TOPs only.

Prevalence and Perceived Value of SRTM

Table 2.9-1 summarizes responses to general questions about SRTM. Most RCs (88 percent) and 32 percent of those responding uniquely as TOPs indicate that their organizations have an SRTM tool. In addition, 95 percent of respondents with operational SRTMs consider the features “essential” or “desirable” for providing situational awareness.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, “32/38=84%” means that 32 of a total of 38 respondents, or 84% of respondents, gave the indicated response.

General Survey Questions	All	RCs	TOPs
Do you have SRTM?	22/45 = 49%	14/16 = 88%	8/25 = 32%
Is your SRTM operational?	21/22 = 95%	13/14 = 93%	8/8 = 100%
If it is not operational, do you plan to make your SRT) operational?	1/1 = 100%	1/1 = 100%	0/0 = NA
Do you rate your SRTM “essential” as a reliability tool for situational awareness?	11/21 = 52%	8/13 = 62%	3/8= 38%
Do you rate your SRTM “desirable” as a reliability tool for situational awareness?	9/21 = 43%	4/13 = 31%	5/8 = 63%
Do you rate your SRTM to be of “minimal value” as a reliability tool for situational awareness?	1/21 = 5%	1/13 = 8%	0/8 = 0%
Do you rate your SRTM to be of “no value” as a reliability tool for situational awareness?	0/21 = 0%	0/13 = 0%	0/8 = 0%

Table 2.9-1 — General Responses Regarding SRTM

Respondents’ high opinion of SRTM is conveyed by comments such as the following:

> “This tool allows [us] to debug cases without affecting the Real Time System.”
>
> “Sensational tool to debug real-time problems without affecting real-time applications.”
>
> “Excellent feature to find the convergence problem in a network solution.”

Characteristics of SRTM Applications

Most (86 percent) of respondents who have operational SRTM tools report that their SRTM is either off-the-shelf or customized somewhat. Most (81 percent) report having acquired their SRTM from their SCADA/EMS vendor. A preponderance (91 percent) report that their SRTM is fully integrated with either their production or non-production SCADA/EMS system (see Table 2.9-2). These results indicate that SRTM is a standard application offered by EMS vendors and is feasible to implement although most users perform some level of customization.

SRTM Characteristics	All	RCs	TOPs
Highly customized	3/21 = 14%	0/13 = 0%	3/8 = 38%
Off-the-shelf with some customization	12/21 = 57%	10/13 = 77%	2/8 = 25 %
Off-the-shelf	6/21 = 29%	3/13 = 23%	3/8 = 38%
Supplied by SCADA/EMS vendor	17/21 = 81%	11/13 = 85%	6/8 = 75%
Supplied by other vendor	2/21 = 10%	2/13 = 15%	0/8 = 0%
Developed in-house	2/21 = 10%	0/13 = 0%	2/8 = 25%
Fully integrated with production SCADA/EMS	18/21 = 86%	10/13 = 77%	8/8 = 100%
Fully integrated with non-production SCADA/EMS	1/21 = 5%	1/13 = 8%	0/8 = 0%
Interfaced to production SCADA/EMS	2/21 = 10%	2/13 = 15%	0/8 = 0%
Stand-alone	0/21 = 0%	0/13 = 0%	0/8 = 0%

Table 2.9.2 — Characteristics of SRTM

Most (62 percent) of RCs who have operational SRTM applications report that EMS/IT support staff are the primary users. TOP responses suggest that system operators and/or other control room staff, operations support staff, or EMS/IT support staff are all equal users (see Table 2.9-3). Note that each respondent could choose multiple primary users. Survey results indicate that it is primarily support staff, not system operators, who use SRTM, but a relatively high percentage of TOPs rely on system operators and/or other control room staff to use SRTM.

Primary SRTM Users	All	RCs	TOPs
System operators	8/21 = 38%	3/13 = 23%	5/8 = 63%
Operations support staff	11/21 = 52%	6/13 = 46%	5/8 = 63%
EMS/IT support staff	13/21 = 62%	8/13 = 62%	5/8 = 63%
Supervisory/Management	3/21 = 14%	0/13 = 0%	3/8 = 38%
Others	1/21 = 5%	0/13 = 0%	1/8 = 13%

Table 2.9-3 — Primary Users of SRTM

Most respondents that have an operational SRTM application report that it can simulate NTP, topology error detection, state estimator, and contingency analysis. Only a few report that they can simulate CFLA or other applications (see Table 2.9-4). Note that each respondent could choose multiple applications.

Applications	All	RCs	TOPs
Network topology processor	20/21 = 95%	12/13 = 92%	8/8 = 100%
Topology error detection	13/21 = 62%	7/13 = 54%	6/8 = 75%
State estimator	19/21 = 90%	12/13 = 92%	7/8 = 88%
Contingency analysis	19/21 = 90%	13/13 = 100%	6/8 = 75%
Critical facility loading assessment	1/21 = 5%	1/13 = 8%	0/8 = 0%
Others	3/21 = 14%	3/13 = 23%	0/8 = 0%

Table 2.9-4 — Real-Time Applications that SRTM Can Simulate

Recommendations for New Reliability Standards

Requirement R9 of NERC Standard IRO-002 mandates that RCs have plans and procedures for minimizing tool outages:

> [E]ach Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.

RTBPTF focuses on evaluating the capabilities of operators' critical real-time tools, not how those applications are maintained. RTBPTF believes that requirement R9 is sufficient to maintain the viability of analytical tools and does not recommend developing specific SRTM standards at this time.

Although the RTBPTF recommends no specific SRTM standards, SRTM capabilities should be considered when developing standards for maintaining and supporting other (critical) real-time applications that do require standards. Rather than requiring standards for SRTM, RTBPTF recommends establishing operating guidelines.

Recommendation – G7

Use the study real-time maintenance application to reproduce real-time snapshots.

Recommendations for New Operating Guidelines

Because survey results show that most RCs have, successfully use, and highly value SRTM, RTBPTF considers it appropriate to develop operating guidelines for this tool. The operating guidelines should help SRTM support the standards established for the critical real-time applications that do require standards (e.g., NTP, state estimator, and contingency analysis). SRTM supports the notion of "[i]mprove[d] IT forensic and diagnostic capabilities," as described in Recommendation 17 of the *Outage Task Force Final Blackout Report.* Users of real-time network applications may be able to improve their maintenance tools and practices based on achieving the capabilities recommended in the following operating guidelines for SRTM.

1. Whoever performs the RC, BA, or TOP function should be capable of using their SRTM application to simulate, at a minimum, the following real-time network applications:
    - NTP
    - state estimator
    - contingency analysis

2. If an entity implements its SRTM capability in a non-production environment, whoever performs the RC, BA, or TOP function should be capable of quickly and easily synchronizing that environment to the production environment (via network model, software, or user interface) so that real-time problems or snapshots can be reproduced.

3. Whoever performs the RC, BA, or TOP function should have the following SRTM capabilities:

- Ability to initiate the SRTM application from each of the critical real-time applications
- Ability to automatically save and archive real-time cases from various time periods
- Ability to automatically save and archive real-time aborted and non-converged cases
- Ability to initiate the SRTM application from an archive of historical real-time cases
- Ability, if requested, to save an SRTM case for future use
- Ability of SRTM to precisely duplicate real-time applications
- Ability to initiate study power flow and other study applications from a saved SRTM-analyzed case
- Possession of a distinct SRTM user interface

Recommendation – A10

Obtain additional information on how the study real-time maintenance application is utilized to enhance debugging capability.

Areas Requiring More Analysis

Before NERC establishes operating guidelines for SRTM and standards for maintaining and supporting critical real-time network applications, RTBPTF recommends obtaining additional details about how most industry members utilize SRTM capabilities. Based on a few survey comments, some respondents may believe that some of the capabilities of their study network application and DTS represent full SRTM capabilities. Although this idea is not necessarily incorrect, there are some subtle differences among these capabilities.

It may be impossible, for example, to recreate all real-time contingency analysis problems using study contingency analysis, because the base case for real-time contingency analysis may be the real-time state estimator solution whereas the base case for study contingency analysis may be a power-flow solution derived from the real-time state estimator solution.

It may be impossible to use DTS to recreate all problems in state estimator solutions because the state estimator in DTS may use measurements from the simulation rather than from real-time SCADA data.

If the full range of SRTM capabilities is accessible, network applications can be run and debugged exactly as they are, so that problems can be reproduced. If SRTM capabilities are implemented on a non-production, rather than production, EMS that system must be synchronized (regarding network model, software, and user interface) with the production EMS system to enable problems to be reproduced.

Examples of Excellence

RTBPTF cites as an example of excellence the use of an SRTM by PJM that includes a user interface that looks and feels exactly like the production network applications (See EOE-11 in Appendix E). SRTM allows PJM to quickly and easily recreate, debug, and resolve network applications problems without impacting the real-time network applications and use of this application has increased the overall availability of the real-time network applications.

Section 2.10
Voltage Stability Assessment

Definition

Voltage stability is defined as how much more load or transfer the system can sustain in a given direction before it encounters voltage instability. Voltage stability analysis (VSA) is an application that executes in near real-time and aids in the determination of system operating limits based on the voltage stability assessment using a recent snapshot of the real-time system. VSA may derive minimum voltages at key buses below which voltage collapse might occur if the system experiences additional stresses. It may also provide information on minimum dynamic reactive reserves required in local areas.

Note that this definition is not referring to offline voltage stability analysis tools that are usually used by engineering staff for medium-term or long-term studies. However, if such tools are used for studying near-real-time snapshots in answer to voltage stability questions by operators, they would be included in the VSA section of the Real-Time Tools Survey.

Summary of Findings

The VSA section of the Real-Time Tools Survey evaluates use of documented practices for monitoring voltage conditions. Survey responses indicate that although VSA applications are clearly useful, they apparently have not yet reached a stage of maturity that would render them a critical tool for reliable system operation.

VSA tools are used by a limited group of respondents. Only 6 out of the 14 reliability coordinators (RCs) (43 percent) and 6 out of the 24 transmission operators (TOPs) (25 percent) who responded to this section of the survey report having VSA capability. Just 5 RCs (36 percent) and 3 TOPs (13 percent) report having an operational VSA application. Interest in VSA may be growing, however, because 2 RCs and 5 TOPs plan to add a VSA package. In addition, 3 RCs and 6 TOPs plan to make their current application operational. The 5 RCs who have operational VSA applications deem the application ”essential” or “desirable” for monitoring system reliability. In addition, 2 out of 3 TOPs consider the application “desirable,” although one TOP considers it of “minimal” value.

Three RCs (of 5 responding) and 2 TOPs (of 3 responding) reported that their VSA applications can assess voltage stability (i.e., indicate pass/fail) for a set of contingency conditions. Some respondents indicated even though VSA is not widely used today, it could be of greater benefit if it was able to identify voltage stability margins and optimize the margin of voltage stability. The applications should be designed to display both the enhanced stability margin and a range of corrective actions. With further development, VSA applications have the potential to become another critical tool for monitoring system reliability in real time.

Users

Survey respondents identify operations planning staff, RCs, system operators, and control room staff as the primary users of VSA. Respondents who have operational VSA applications report that operations planning staff are the users (all 5 RCs and all 3 TOPs). Three RCs include control room operators as VSA users, while a few respondents identify EMS support staff, system planners, and "others" as users.

Functionality and Analytical Methods

Most VSA applications were developed in-house or by a third-party vendor other than the EMS vendor (reported by 4 out of 5 RCs and 2 out of 3 TOPs). Two out of 5 RCs (40 percent) and one out of 3 TOPs (33 percent) report that their application is highly customized. No RCs and only one TOP report using an off-the-shelf VSA product.

Four out of 5 RCs and both TOPs who responded report that their VSA applications are interfaced with state estimator solutions. VSA is most frequently interfaced with the real-time state estimator and contingency analysis applications although it was reported to be integrated with other applications such as unit commitment.

Three out of 5 RCs and 2 out of 3 TOPs report that they can assess voltage stability (i.e., determine pass/fail) for a set of contingency conditions derived from current system conditions. Three RCs and 2 TOPs consider this feature to be desirable or essential. Four out of 5 RCs report that their VSA application is used to evaluate fewer than 100 contingencies. While 1 respondent noted that it maintains a separate contingency list, 3 out of 5 RCs reporting indicated that the contingency list analyzed is derived from the EMS. Two of the 3 TOPs reporting also indicated the contingency list used is derived from the EMS.

The VSA application typically executes as a real-time tool. Three out of 5 RCs and all 3 TOPs who use the application report relying on a periodic trigger to execute VSA. Similar percentages use manual triggers. Respondents do not report using event or disturbance triggers. Frequency of execution ranges from once every minute to once every 60 minutes. The few RCs who responded to this section of the survey report that the application takes from 2 to 10 minutes (as measured by the wall clock) to execute.

Only 3 RCs and 2 TOPs responded to questions about the analytical methods that their VSA program employs to assess voltage stability. The applications of 3 RCs and both TOPs utilize Power/Voltage (PV) analysis. Other analytical methods include Reactive/Voltage (QV) analysis (0 RCs but both TOPs reporting they have the application); singularities in the Jacobian matrix (1 RC); power flow non-convergence (1 RC); and detailed time simulation (1 RC). Two respondents comment that they use other methods such as a ”continuation power flow” or ”model analysis” to assess the network’s voltage stability.

Two out of 5 RCs and 3 out of 4 TOPs state that their VSA applications calculate margins of voltage stability (see definition above). TOPs and RCs responded somewhat differently to the question of perceived value of this function as all 3 TOPs who have this feature say they use the ability to calculate voltage stability margins and consider it desirable. In contrast, although just 2 RCs report using a voltage stability margin application, both consider it essential. Three RCs and 1 TOP also indicated that they would consider the feature desirable if they had the ability to calculate voltage stability margins.

One out of 2 RCs reports that the application automatically assesses stability for increasing levels of load, and both RCs responding to the question indicate that their program automatically assesses stability for increasing levels of power transfer from an area (or set of areas) to another area. One of 3 TOPs responded that they use a load-increase-based method, and 1 of 3 TOPs responded that they use the increasing power transfer technique to assess voltage stability margins. Another TOP notes that they use a “direct analytical method” but does not describe the feature further.

The survey also asked whether respondents were incorporating advanced VSA tools to develop optimized margins of voltage stability. No RCs and only 1 out of 4 TOPs report having the capability to optimize or develop combinations of mitigation options to increase the system’s margin of voltage stability in near-real time for a set of contingency conditions with the ability to display both the enhanced stability margin and a set of corrective actions. Although only one entity reports using this feature, of respondents who lack the feature, all RCs (5) and TOPs (3) deem it desirable.

Three out of 5 RCs and 2 out of 4 TOPs report that their VSA applications have tools that display/visualize the level of voltage stability as an index of PV or QV curves or via tabular displays. Just 2 RCs and 2 TOPs report using the features although those same 4 respondents rate the feature “desirable” or “essential” (see Table 2.10-1).

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, “32/38=84%” means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

What Techniques Does the Program Use to Visualize the Voltage Stability of Your Power System Network?	All Respondents	RCs
Color-coded meters	1/4 = 25%	1/2 = 50%
Graphs of PV or QV curves	0/ 4 = 0%	0/2 = 0%
Other(s)	4/4 = 100%	2/2 = 100%
Spatial visualization of voltage stability margins by the boundaries	3/4 = 75%	2/2 = 100%
Tabular displays	0/4 -= 0%	0/2 = 0%
Voltage stability index	1/4 = 25%	1/2 = 50%

Table 2.10-1 — Techniques Used to Display Voltage Stability

One respondent comments that their application can generate SCADA alarms. Four RCs continuously monitor the availability of their VSA application, and 3 notify on-call or on-site support staff of application failures.

Recommendations for New Reliability Standards

RTBPTF is not recommending the development of new reliability standards related to VSA. Given the limited application of VSA within the industry, as indicated by the survey results summarized above, RTBPTF does not recommend developing new reliability standards for VSA applications.

Recommendations for New Operating Guidelines

RTBPTF is not recommending Operating Guidelines related to VSA. Given the limited application of VSA within the industry, as indicated by the survey results summarized above, RTBPTF does not recommend developing new operating guidelines for VSA applications.

Recommendation – A11

Assess the voltage stability assessment (VSA) application to learn how the VSA can be enhanced to become more widely used.

Areas Requiring More Analysis

RTBPTF believes that the industry would benefit from having NERC standards that support wide-area security of the bulk electric transmission system through real-time tools that assess voltage stability boundaries. A VSA tool could be used to generate the data required to determine this secure boundary and to identify appropriate corrective actions if needed. At present, VSA tools are used only by operations planners and by very few organizations. The survey did not determine whether the lack of wide use of this tool is attributable to the application being problematic, the results being unreliable, or the results failing to provide clear and actionable information. RTBPTF recommends that VSA capabilities be assessed further to learn why VSA tools are not used more widely, and how they could be enhanced to become more useful and more broadly used.

Examples of Excellence

RTBPTF cites the work of PJM to enhance its real-time VSA to provide control actions to avoid collapse and increase stability margins as an example of excellence (See EOE-12 in Appendix E).

Section 2.11
Dynamic Stability Assessment

Definition

Dynamic Stability Assessment (DSA) is an application (or a suite of applications) executing in near-real time that aids in the determination of stability-related system operating limits using a snapshot of the real-time system (i.e., current state estimator output). It may also provide an indication of dynamic stability margin for the most critical fault/contingency condition.

Note that this definition is not referring to offline stability analysis tools that are usually used by engineering staff for medium-term or long-term studies. However, if such tools are used for studying near-real-time snapshots to answer operators' voltage stability questions, these tools should be included in the DSA section of the Real-Time Tools Survey.

Summary of Findings

The DSA section of the Real-Time Tools Survey evaluates use of DSA applications for monitoring system conditions. Although DSA applications are useful, the responses to the DSA section of the Real-Time Tools Survey indicate that DSA applications are used very little; they apparently have not yet reached a stage of maturity that would render them a critical tool for reliable system operation.

Industry members appear interested in expanding the use of DSA, however. When the applications are further developed, they may have the potential to become another critical tool for monitoring system reliability in real time. As suggested by some of the survey responses, DSA applications would be enhanced if they were able to identify margins of dynamic stability and to optimize or search for combinations of mitigation options to increase the system's margin of stability.

As noted above, the applications apparently have not fully matured, but survey comments such as the following suggest that there is interest in developing DSA applications:

> Our Voltage/Transient Stability tools are not in production yet. We are in the early stages of implementing this tool as a real-time application for our reliability group. We feel that this is a desirable tool that will give the reliability folks another resource to maintain a safe and secure operational network.

It also appears that new installations and application enhancements are either in progress or planned for future implementation that could increase the value of this tool to that of an essential application. In the survey responses, 5 RCs and 5 TOPs state that they plan to add DSA to their suite of applications. This evidence suggests that industry members are interested in using DSA even though only 3 out of 16 RCs (19 percent) and 2 out of 23 TOPs (9 percent) report having a DSA application at this time, and just one RC (and no TOPs) state that their DSA application is operational. Respondents report that the primary users of DSA are operations planning staff and RCs. Results are displayed in various formats, such as a dynamic stability index or a tabular display, color-coded meters, color-coded bar graphs, and spatial visualization.

Based on survey results, DSA software packages are available from SCADA and/or EMS or other vendors. The applications can be applied off-the-shelf or with some customization. Just one TOP indicates that their application was developed in-house.

Functionality and Analytical Methods

Another indication that the application may not yet be mature is that respondents identified a variety of analytical methods for DSA applications, with no single method (or even two methods) emerging as dominant. The applications utilize various approaches, including time-domain simulation, energy function, equal-area criterion, and modal analysis. One RC states that its application utilizes “other direct analytical methods.”

Survey respondents report that a variety of periodic, manual, event or disturbance triggers are employed to start the DSA application.

Online DSA applications are being designed to evaluate dynamic stability not only for the given base conditions but also under various contingency conditions. The contingencies to be studied can be defined from the EMS or via a separate list. Survey results suggest that the applications can, and should, be designed to calculate dynamic stability margins when examining cases with increased loading or power-transfer levels. However, other evidence that the approach to this type of problem is not well established is that some systems estimate critical clearing times and others use energy function values to determine the instability point. Of interest was that 2 respondents report that their software is designed to optimize or search mitigation options to increase the system’s margin of stability in near-real time given a set of contingency conditions. This suggests that the results of DSA can serve an important role.

Recommendations for New Reliability Standards

Given the minimal use of DSA within the industry, as indicated in the survey results summarized above, RTBPTF is not recommending the development of new reliability standards related to DSA.

Recommendations for New Operating Guidelines
Given the minimal use of DSA within the industry, as indicated in the survey results summarized above, RTBPTF is not recommending Operating Guidelines related to Dynamic Stability Assessment.

Recommendation – A12

Assess the dynamic stability assessment (DSA) application to learn how the DSA can be enhanced to become more widely used.

Areas Requiring More Analysis

RTBPTF believes that the industry would benefit from having NERC standards that support wide-area security of the bulk electric system through real-time tools that could identify stability limits or boundaries which define areas of secure operation. Even though current DSA tools may not yet be mature, it appears that many in the industry believe that a DSA tool could be used to generate the data required to identify secure operating boundaries. Consequently, RTBPTF recommends that DSA be assessed further to learn how it currently operates and how it could be enhanced to become more useful, more valuable and more widely used.

Examples of Excellence

RTBPTF did not identify any Examples of Excellence related to DSA.

Section 2.12
Capacity Assessment

Definition

A capacity assessment is an evaluation of the planned and actual amount of power a system can generate. A capacity assessment gives system operators information about the location and availability of critical generating sources and identifies deficiencies in operating reserves. A capacity assessment always considers the real power (MW) that can be generated. When it also includes reactive power capacity (Mvar), it may also consider static devices, such as capacitor banks and reactors.

Background

Power system operators use various methods to monitor the generation resources available to meet power system demands that are changing throughout the day. Unit commitment plans and generation schedules usually are established in advance using one or more applications that prescribe ways to supply predicted system loads. Operators use processes and/or applications that monitor generating reserves on all or parts of the system to make sure capacity is adequate to meet credible generation contingencies and other deviations from the plan. These processes are discussed further in Section 3.1, Reserve Monitoring, of this report.

The applications that assess capacity in real time track both planned and actual generating schedules. These applications are designed to give operators a real-time view of all resources that could be called on if an unplanned event were to result in insufficient capacity in real time.

Tools for assessing capacity complement other wide-area tools and enhance situational awareness. Operators in areas subject to voltage difficulties benefit from increased situational awareness that includes a trustworthy assessment of available, unused real and reactive power capacities. As noted in Section 3.1, Reserve Monitoring, the balance resource and demand standards appear to clearly define real power (MW) operating reserves but not reactive power (Mvar) reserve requirements. Likewise, the calculation of reactive reserves is not well defined in that or any other NERC standard.

Summary of Findings

The capacity assessment section of the Real-Time Tools Survey examines operation, maintenance, and practices related to capacity assessment applications, as reported by those involved in operating transmission systems. This section also addresses the key issues faced by those who use capacity assessment applications.

Survey results reveal that applications for assessing capacity are widely used and generally regarded as important for maintaining awareness of system reliability. Capacity assessment applications, used primarily by control room staff, may incorporate various types of data but always utilize SCADA data. The applications typically receive no scheduled maintenance but are maintained when an alarm indicates the need.

Prevalence and Perceived Value of Applications

As illustrated in Table 2.8-1, 53 percent of all respondents and 69 percent of RCs state that they have a capacity assessment application. Most respondents who have such an application (64 percent) consider it “essential” for situational awareness. Another 28 percent find it “desirable” for situational awareness. Table 2.12-1 summarizes responses to general questions about capacity assessment applications.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, “23/43=53%” means that 23 out of a total of 43 respondents, or 53% of respondents, gave the indicated response.

Survey Question	All Respondents	RCs	Others
Do you have a capacity assessment (or equivalent) application?	23/43 = 53%	11/16 = 69%	12/27 = 44%
Is this application operational?	23/23 = 100%	11/11 = 100%	12/12 = 100%
If you do not have this application, do you plan to add it in the future?	2/19 = 11%	2/5 = 40%	4/24 = 17%
If planned or operational, do you consider it essential?	16/25 = 64%	10/13 = 77%	6/12 = 50%
If planned or operational, do you consider it desirable?	7/25 = 28%	3/13 = 23%	4/12 = 33%
Do you consider the application of minimal or no value?	2/25 = 8%	0/13 = 0%	2/12 = 17%

Table 2.12-1 — Prevalence and Perceived Value of Capacity Assessment Applications

Users of Applications

Capacity assessment applications are used or intended for use by operators and other support personnel (see Table 2.12-2). All respondents that have capacity assessment applications report that these applications are used primarily by operators or control room staff. Approximately 40 percent of all respondents indicate that their capacity assessment applications are also used by operations support staff. These survey results indicate that capacity assessment applications are used widely for monitoring system conditions and energy management issues.

Users	All Respondents	RCs	Others
System operators and/or other control room staff	25/25 = 100%	13/13 = 100%	12/12 = 100%
Management staff	8/25 = 32%	4/13 = 31%	4/12 = 33%
Support staff and others	10/25 = 40%	3/13 = 23%	7/12 = 58%

Table 2.12-2 — Users of Capacity Assessment Applications

Sources of Data for Applications

The survey asked respondents who report using capacity assessment applications what sources of data the application utilizes. All respondents report using SCADA data, but many also rely on manual entries and other sources that do not necessarily provide real-time data. Table 2.12-3 summarizes the responses.

Sources of Data	All Respondents	RCs	Others
SCADA	23/25 = 92%	12/13 = 93%	11/12 = 92%
Manual data	15/25 = 60%	8/13 = 63%	7/12 = 58%
IDC	0/25 = 0%	0/13 = 0%	0/12 = 0%
External applications	7/25 = 28%	6/13 = 46%	1/12 = 8%
Other	3/25 = 12%	3/13 = 23%	0/12 = 0%

Table 2.12-3 — Sources of Data for Capacity Assessment Applications

Three respondents note that “resource plans, load forecast,” and “other data” (typically derived from market data) provide input to capacity assessments.

Approximately 59 percent of all respondents and all RC respondents report they can monitor reactive power capacity (Mvar) as well as real power capacity (MW). Only 12 percent of all respondents indicate that they monitor other types of capacity. Two users note that they monitor the effects of reserves on the ability of critical interfaces to withstand select double-contingencies. These latter responses indicate that some respondents confuse the notion of the various types of capacity (MW, Mvar, other) with how capacity is evaluated (base case, contingency, etc.). The survey questions may not have highlighted this distinction adequately.

Support for Applications

Capacity assessment applications generally do not receive routine attention from support personnel. About 62 percent of all users (57 percent of RCs and 64 percent of TOPs) note that they report any application failures to support personnel. A majority (63 percent) report that support is not automatic or scheduled. Instead, operators call support if an alarm indicates that the application is not functioning. Few (21 percent overall and only 13 percent of RCs) maintain the applications on a regular (weekly) basis rather than an as-needed basis.

Recommendations for New Reliability Standards

Section 3.1, Reserve Monitoring, presents RTBPTF's recommendations for new standards related to operating reserves referenced in this section. Specifically, RTBPTF recommends that requirements be added to existing standards so that operators will monitor critical components of real power operating capacities that affect these reserve quantities.

Recommendations for New Operating Guidelines

RTBPTF is not recommending operating guidelines related to capacity assessment.

Recommendation – A13

Analyze the need to define reactive power (Mvar) capacity requirement and use a Mvar assessment application.

Areas Requiring More Analysis

RTBPTF recommends further analysis of applications that provide comprehensive capacity assessments. This analysis should be coordinated with analysis of tools used to evaluate operating and capacity reserves in Section 3.1, Reserve Monitoring.

Because of the shortcoming noted above, that the current BAL standards do not define reactive power requirements, RTBPTF identified reactive reserve requirements as a major issue; this is discussed in detail in the Introduction to this report. Specifically, RTBPTF believes that mandatory requirements for real-time tools for reactive reserve monitoring would be highly desirable; however, before such recommendations can be formulated, NERC must define technically justified and feasible-to-implement requirements for determining the appropriate amount and location of acceptable reactive reserves and clarifying how reliability coordinators should monitor these reserves.

Examples of Excellence

RTBPTF did not identify any Examples of Excellence related to capacity assessment.

Section 2.13
Emergency Tools

Definition

Emergency tools are applications or procedures that operators use when the power system enters or is about to enter an emergency.[75]

Background

Maintaining the reliability of a power-generating or transmitting facility is a complex enterprise that requires trained and skilled operators, sophisticated computers and communications, and careful planning and design. NERC has developed standards for operating and planning electric systems to safeguard the reliability of transmission grids. The standards are based on seven key concepts that are identified in the *Outage Task Force Final Blackout Report*.[76]

1. Continuously balance power generation and demand.
2. Balance reactive power supply and demand to maintain scheduled voltages.
3. Monitor flows over transmission lines and related facilities so as to stay within thermal (heating) limits.
4. Keep the system in a stable condition.
5. Operate the system so that it remains reliable even if a contingency occurs, such as the loss of a key generator or transmission facility (the "n-1 criterion").
6. Plan, design, and maintain the system to operate reliably.
7. Prepare for emergencies.

The *Outage Task Force Final Blackout Report* further states:

> System operators are required to take the steps to plan and operate a reliable power system, but emergencies can still occur because of external factors such as severe weather, operator error, or equipment failures that exceed planning, design, or operating criteria. For these rare events, the operating entity is required to have emergency procedures covering a credible range of emergency scenarios.[77]

Current NERC standards assign RCs the authority to direct TOPs and BAs to shed load, and TOPs and BAs are required to comply with those directives. No

[75] The NERC Glossary defines "emergency" as "[a]ny abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System."
[76] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. pp. 6–7.
[77] Ibid. p. 10.

standards, however, mandate RCs to maintain situational awareness of their own capability to shed load under real-time operating situations.

Tools/applications for use during a range of credible emergency conditions or scenarios are essential to maintain reliability of the bulk electric system. The Real-Time Tools Survey examined the following types of emergency tools:

- Residential Load or Demand-Side Management – This type of tool enables operators to curtail residential electricity demand[78] for specific appliances. Residential load or demand-side management (DSM) tools consist of the planning, implementing, and monitoring activities that are designed to encourage residential consumers to modify their level and pattern of electricity usage. These activities are also designed to allow shaping of electricity demand through direct computer control of specific appliances. For example, when necessary, operators could turn off air-conditioners of residential customers that sign up for a residential DSM program to reduce electricity demand.

- Commercial/Industrial Load or Demand-Side Management – This type of tool enables operators to curtail commercial/industrial electricity demand. This type of tool is similar to residential Load or DSM but is applied to commercial/industrial customers. A typical application of this type of tool is demand reduction in which operators use direct computer control to disconnect the electric supply feed from the supplying entity.

- Load Reduction by Voltage Reduction – This type of tool enables operators to curtail electricity demand by reducing distribution-level voltages. This scheme usually involves direct computer control (via SCADA systems) to automatic voltage regulating relays on LTC power transformers and step voltage regulators. Controlling the dry contact closure to the regulating relay boosts the sensed voltage of the voltage regulating relay and thus reduces its center band voltage to a lower level.[79] This causes a reduction of the distribution voltage schedule, which reduces electricity demand for a short period.

- Rotating Load Shed – This type of tool enables operators to curtail load by initiating or scheduling load shedding. The *Outage Task Force Final Blackout Report* defines "load shedding" as "… the process of deliberately removing (either manually or automatically) pre-selected customer demand from a power system in response to an abnormal condition, to maintain the integrity of the system and minimize overall customer

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[78] The NERC Glossary defines "demand" as "[t]he rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time" or "[t]he rate at which energy is being used by the customer."

[79] http://www.beckwithelectric.com/infoctr/appnotes/App16.pdf

> outages."[80] For this type of tool, rotating load shed refers only to manual load shedding scheduled or initiated by operators via computer control.

Although not all personnel have direct control over all of the emergency tools discussed in the Real-Time Tools Survey (i.e., most RCs do not have direct control over load-shedding applications), if RCs has the tools to monitor the status of emergency tools under their purview, this would enhance situational awareness for both TOPs and RCs. Results form the Emergency Tools section of this report go hand-in-hand with the findings reported in Section 3.5, Load Shed Capability, of this report.

Summary of Findings

The primary finding of the emergency tools section of the Real-Time Tools Survey is that certain types of emergency tools are not widely available, nor are they widely used throughout the industry. The most commonly used emergency tool is rotating load shed, as reported by a small number of respondents. Although few respondents have the emergency tools described in this section, they are nonetheless required to be aware of the situations monitored or controlled by the tools.

Prevalence of Emergency Tools

Table 2.13-1 summarizes the responses to the survey section regarding access to emergency tools. Only 46 percent of respondents to this section of the survey (19 out of 41) indicate that they have emergency tools. This result is surprising given that current NERC reliability standards implicitly require an accessible and functional operator-controlled load-shedding capability (through a tool/application such as rotating load shed). Requirement R2 of Standard EOP-001, for example, states that:

> [T]he Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

In addition, the purpose of Standard EOP-003 is described as: "[a] Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection." Requirement R8 of EOP-003 states, "[E]ach Transmission Operator or Balancing Authority shall

[80] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 216.

have plans for Operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency." All of these requirements imply the necessity for operator-controllable, emergency tools for shedding load.

The low percentage of respondents who report having emergency tools is inconsistent with the findings described in Section 3.5, Load-Shed Capability. In that section of the survey, 74 percent (34 out of 46) of respondents report having some sort of documented practices for maintaining situational awareness of load-shed capability. In short, in the emergency tools section of the survey, 46 percent of respondents indicate they have emergency tools, but in the load-shed section of the survey, 74 percent indicate they have documented practices for maintaining awareness of load-shed capability. This inconsistency may mean that some respondents who report having documented practices for load-shed capability do not use an operator-controlled emergency tool. Instead, these entities may depend entirely on automatic field equipment [i.e., under-frequency load shed (UFLS) or under-voltage load shed (UVLS) relays] to provide load-shed capability.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, "32/38=84%" means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

Respondents	Do You Have Emergency Tools, such as Residential Demand-Side Management or Rotating Load Shed?
All	19/41 = 46%
RCs	5/14 = 36%
Others	14/27 = 52%

Table 2.13-1 — Prevalence of Emergency Tools

Perceived Value of Emergency Tools

The survey asked respondents to rate any operational emergency tools that they have available in terms of their situational awareness value. Table 2.13-2 summarizes the responses.

Respondents	How do You Rate Your Emergency Tools as a Reliability Tool for Situational Awareness?	
	Application is "essential"	Application is "desirable"
All	11/18 = 61%	7/18 = 39%
RCs	4/6 = 67%	2/6 = 33%
Others	7/12 = 58%	5/14 = 36%

Table 2.13-2 — Perceived Value of Emergency Tools

Use of Emergency Tools

The data indicate that most respondents who have emergency tools consider them "essential" reliability tools for situational awareness. The survey data also reveal that emergency tools are not used as widely as more common, readily available tools/applications such as the state estimator or contingency analysis. Fewer respondents answered the emergency tools part of the survey than responded to sections concerning other tools/applications. Table 2.13-3 summarizes respondents' use of the emergency tools. RCs are listed separately.

Application	Do You Have this Emergency Tool?			Do You Use this Emergency Tool?		
	All	RCs	Others	All	RCs	Others
Residential load or DSM	6/20 = 30%	2/6 = 33%	4/14 = 29%	6/6 = 100%	2/2 = 100%	4/4 = 100%
Commercial/industrial load or DSM	12/20 = 60%	3/6 = 50%	9/14 = 64%	12/12 = 100%	7/7 = 100%	5/5 = 100%
Load reduction by voltage reduction	6/20 = 30%	2/6 = 33%	4/14 = 29%	6/6 = 100%	2/2 =1 00%	4/4 = 100%
Rotating load shed	17/20 = 85%	4/6 = 67%	13/14 = 93%	12/17 = 71%	4/4 = 100%	8/13 = 62%

Table 2.13-3 — Use of Emergency Tools/Applications

The primary finding of this survey section is that certain types of emergency tools are not widely available or used within the industry. Table 2.13-3 shows that rotating load shed is the most commonly used operational emergency tool, as reported by a relatively small number of respondents. The recommendations made in Section 3.5, Load-Shed Capability, regarding documented practices for keeping operators aware of the status, availability, magnitude, and time-to-deploy of all load that can be shed on an emergency basis, should be considered in the context of the recommendations made below.

Recommendations for New Reliability Standards

RCs prepare reliability assessments, provide a wide-area view of reliability, and coordinate emergency operations in real time for one or more balancing authorities. As specified in requirement R4 of Standard IRO-005, one of their responsibilities is:

> [A]s portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.

Standard IRO-005 (requirement R3) does not stipulate that the RC must have direct control over load shedding. The standard does specify, however, that RCs have the authority to direct load shedding when necessary. Reliability coordinators are not currently required to be aware of the system load-shed capability required to address a potential or actual IROL violation

Recommendation – S15

Provide real-time awareness of load-shed capability to address potential or actual IROL violations.

RTBPTF Recommendation

Based on survey results, RTBPTF developed a proposed requirement and performance measure to clarify that RCs must be kept aware of load-shed capability in particular because that factor is critical to the ability to address a potential or actual IROL violation.

RTBPTF recommends that Standard IRO-005 be enhanced to require the RC to be aware of the load-shed capability needed to address a potential or actual IROL violation within its area of responsibility. RTBPTF developed the following proposed requirement (PR):

PR1. Each Reliability Coordinator shall have real-time awareness of load-shed capability needed to address a potential or actual IROL violation within its area of responsibility.

RTBPTF developed the following proposed measure (PM) for the above requirement.

PM1 Each Reliability Coordinator shall be required to demonstrate system load-shed capability by having a display (or visualization technique) that shows the real-time status and amount of MW available for shedding load within its area of responsibility.

Rationale

The rationale for this recommendation is discussed extensively in Section 3.5, Load-Shed Capability. Current NERC standards assign RCs the authority to direct their TOPs and BAs to shed load, and TOPs and BAs are required to comply with those directives. No standards, however, specifically mandate that RCs maintain situational awareness of the capability to shed load under real-time operating situations. But the RC must know what can be achieved in response to a directive to shed load.

Recommendations for New Operating Guidelines

RTBPTF is not recommending operating guidelines related to emergency tools.

Recommendation – A14

Research how emergency tools and visualization techniques are used in load shedding plans.

Areas Requiring More Analysis

The survey results are insufficient to establish how personnel use emergency tools, including whether any documented procedures are associated with the tools. RTBPTF recommends further analysis in the following two areas related to emergency tools:

- Research the ways load-shedding plans are established in relation to the various emergency tools. In particular, how does the industry coordinate and prioritize the use of emergency tools (i.e., rotating load shed) with automatic load-shedding schemes? Is there variation in practices and implementation?
- Research current techniques and devices for showing operators the status of load-shed capability. How does the operator know how much load the

emergency tool can shed? How is load-shed capability calculated? What visualization techniques are used to display this information?

Examples of Excellence

RTBPTF did not identify any Examples of Excellence related to emergency tools.

Section 2.14
Other Tools (Current and Operational)

Definition

This section of the report reviews reliability tools for situational awareness that are currently available and operational and that are not specifically addressed in other sections. The tools/applications that are discussed are listed below with their respective definitions:

- Congestion Management Application — This tool relieves network congestion within an entity's service territory using operational means that lie within the entity's control authority, i.e., generation redispatch, curtailment of economic transactions within the entity's service area, switching in capacitor banks, opening low-voltage lines, etc. Typically, this tool would be a security-constrained economic dispatch program, an optimal power-flow program, or an heuristic program that searches for the best solution from a set of options. For an ISO or an RTO, this may be part of the LMP application.

- Inter-Regional Real-Time Coordination for Congestion Management Application — This tool may be different from the congestion management application listed above if the entity uses a separate tool for managing congestion caused by transactions that originate and/or terminate outside of the entity's service area. This may also be the NERC IDC if used for managing congestion that involves curtailing transactions outside of the entity's service territory.

- Inter-Regional Real-Time Coordination for Market Redispatch — This tool is to adjust the market dispatch within the entity's service territory in coordination with adjacent RCs to manage the inter-regional congestion problem in real time. This tool may be handled by the entity's congestion management application, or it may be handled through a different process.

- Inter-Regional Voltage Profile Coordination. This tool coordinates the voltage profiles between two or more regions. This application may contain features such as wide-area voltage contour visualization, voltage schedule coordination between regions, etc.

- Short-Term Hydro Scheduling. This real-time tool manages deviations from the long-term optimized schedule for reasons of reliability, e.g., a response to a disturbance control standard (DCS) event, acquiring support for localized voltage control, etc.

- Short-Term Wind Energy Forecasting — This near-real-time tool is used to predict and manage generation in response to the variability of supply from wind energy sources.

- Short-Term Load Forecasting — These tools predict short-term (next 0-60 minutes) loads based on parameters such as short-term weather effects, current load, etc. The results from this tool could be used for predictive redispatch, look-ahead contingency analysis, awareness of scheduled non-conforming load changes, etc.

- Short-Term Weather Forecasting — This tool predicts short-term (next 0-60 minutes) extreme weather that may impact operations, i.e. a lightning prediction tool, Doppler radar, etc.

Summary of Findings

The other tools (current and operational) section of the Real-Time Tools Survey was designed to identify tools that provide advanced functionality and are used widely throughout the industry. With the possible exception of congestion management and short-term load forecasting tools, survey results suggest that usage of advanced functions is not prevalent among survey respondents.

The applications described above may provide entities with enhanced situational awareness for monitoring and assessing conditions or performing actions to maintain the reliability of interconnected bulk electric systems. Based on survey results, however, the applications are not used as widely as the typical suite of reliability analysis applications readily available to the industry (i.e., the state estimator or contingency analysis).

Because so few respondents identify themselves as BAs, the task force could not develop statistically significant conclusions for that group. Therefore, the discussion below focuses on RCs and TOPs.

Prevalence of Tools

Table 2.14-1 summarizes responses from RCs and TOPs to survey questions regarding use of advanced tools. For the RCs and TOPs responding, congestion management, short-term weather forecasting and short-term load forecasting were the only applications available to at least 50 percent of respondents. Even though a limited number of overall survey participants responded to questions in this section, the results suggest that these three applications are more prevalently used than the others that were specifically identified.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, “32/38=84%” means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

Application	Application Available?			Application Operational?		
	All	RCs	TOPs	All	RCs	TOPs
Congestion management	11/41 = 27%	**7/14 = 50%**	4/24 = 17%	10/13 = 77%	6/8 = 75%	4/5 = 80%
Inter-regional real-time coordination of congestion mgt.	8/38 = 21%	6/13 = 46%	2/22 = 9%	8/9 = 89%	6/6 = 100%	2/3 = 67%
Inter-regional real-time coordination of market redispatch	3/31 = 10%	3/12 = 25%	0/17 = 0%	3/4 = 75%	3/3 = 100%	0/1 = 0%
Inter-regional voltage profile coordination	1/31 = 3%	1/12 = 8%	0/17 = 09%	1/3 = 33%	1/2 = 50%	0/1 = 0%
Short-term hydro scheduling	5/32 = 16%	4/11 = 36%	1/18 = 6%	3/4 = 75%	2/3 = 67%	1/1 = 100%
Short-term wind energy forecasting	1/31 = 3%	0/10 = 0%	1/18 = 6%	1/4 = 25%	0/1= 0%	1/3 = 33%
Short-term load forecasting	13/29 = 45%	**7/9 = 78%**	5/17 = 29%	12/14 = 86%	6/7 = 86%	5/6 = 83%
Short-term weather forecasting	14/30 = 47%	4/10 = 40%	**10/17 = 59%**	14/15 = 93%	4/4 = 100%	10/11 = 91%

Table 2.14-1 — Prevalence of Tools/Applications

Perceived Value of Tools

Although the tools may not be used widely throughout the industry, respondents who report having operational tools tend to rate them "essential" or "desirable" for situational awareness. The tools most widely used are those related to congestion management (see Table 2.14-2). One respondent notes that its congestion management tool is "a key component of our congestion management tool for the Inter-ties and is effective."

Application	Rated "Essential"			Rated "Desirable"		
	All	RCs	TOPs	All	RCs	TOPs
Congestion management	8/13=62%	6/8=75%	2/5=40%	4/13=31%	2/8=25%	2/5=40%
Inter-regional real-time coordination for congestion management	6/9=67%	4/6=67%	2/3=67%	2/9=22%	1/6=17%	1/3=33%
Inter-regional real-time coordination for market re-dispatch	1/3=33%	1/3=33%	0/0=0%	1/3=33%	1/3=33%	0/0=0%
Inter-regional voltage profile coordination	1/1=100%	1/1=100%	0/0=0%	0/1=0%	0/1=0%	0/1=0%
Short-term hydro scheduling	2/3=67%	2/2 100%	0/1=0%	1/3=33%	0/2=0%	1/1=100%
Short-term wind energy forecasting	0/3=0%	0/1=0%	0/2=0%	3/3 100%	1/1 100%	2/2=100%
Short-term load forecasting	10/14=71%	6/7=86%	3/6=50%	3/14=21%	0/7=0%	3/6=50%
Short-term weather forecasting	5/14=36%	2/4=50%	3/10=30%	9/14=64%	2/4=50%	7/10=70%

Table 2.14-2 — Perceived Value of Tools/Applications

Recommendations for New Reliability Standards

Because the survey responses indicate that the tools addressed in the "other tools" section are not in common usage throughout the industry, RTBPTF does not recommend any new reliability standards or modifications to standards for these tools.

Recommendations for New Operating Guidelines

RTBPTF does not recommend developing any operating guidelines for any of the tools described in this section. The tools are not in common usage throughout the industry so they do not warrant new operating guidelines.

Recommendation – A15

Analyze the need to use tools for congestion management, voltage profiles, wind-energy forecast, and weather forecast.

Areas Requiring More Analysis

In light of findings (with numerous references to voltage control and congestion management) presented in the *Outage Task Force Final Blackout Report*,[81] RTBPTF does recommend further examination of the NERC IDC and other tools for congestion management and tools for inter-regional voltage profile coordination. RTBPTF also recommends further investigation into tools for load forecasting, wind-energy forecasting, and hydro scheduling because it appears that the industry as a whole would benefit from advances in those areas.

Although the task force developed no recommendations for standards or operating guidelines for these tools, some of them, such as those related to congestion management and inter-regional voltage profiles, are gaining wider acceptance. The task force recommends that these tools and areas of application receive additional analysis.

Only 50 percent of the reliability coordinators and 31 percent of others who responded to the survey indicate they use a tool to help manage congestion. All Eastern Interconnection reliability coordinators, however, are required to use the NERC IDC to manage congestion. Several RTO and ISO entities use a security-constrained economic dispatch application to manage internal and inter-regional congestion and use LMP signals to assist with market redispatch. Because the entities that use security-constrained economic dispatch and LMP applications consider them critical to their ability to maintain system reliability, these tools should be researched further to identify the best available tools and practices and to determine whether standards and/or operating guidelines are needed. Additional research also should be performed on other types of congestion management applications that other entity types use.

Only a few respondents indicate that they possess a specific tool for coordinating inter-regional voltage profiles. Many entities doubtless use other tools and processes for this purpose. Given the relevance of voltage profiles to the August 14, 2003, blackout, the industry should perform further research to ascertain the requirements, current availability/development, and feasibility of implementation for tools to coordinate inter-regional voltage profiles.

Only one respondent describes possessing a tool specifically for forecasting short-term supplies of wind energy. Given the increase in wind energy facilities

[81] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April.

across the country, many entities might benefit from such a tool. The industry should research this tool further to ascertain its requirements, current availability/development, and feasibility of implementation.

Industry members more commonly use tools for short-term hydro scheduling and short-term load forecasting than for wind-energy forecasting. As with short-term wind energy forecasting, short-term hydro scheduling and load forecasting can affect the accuracy of results derived from other applications that utilize these data, such as security-constrained economic dispatch and other tools used for reliability analysis. Therefore, the industry should perform additional research into all three of these forecasting tools to identify the tools and practices that achieve the greatest accuracy.

Although most entities probably subscribe to a commercial weather service, a few may have in-house meteorological staff providing this service. Survey results do not indicate the numbers and types of tools used for short-term weather forecasting. In addition, respondents do not specify what actions they take based on weather-forecast data. Because weather forecast data are typically used as input to load-forecasting tools, they can affect the accuracy of those forecasts. The industry should perform additional research on weather-forecasting tools to identify the tools and practices that achieve the greatest accuracy.

Examples of Excellence

RTBPTF identified the following examples of excellence. Each of the entities described below has developed its own method for using some of the tools/applications described in this section.

RTBPTF cites Bonneville Power Administration’s use of a curtailment wizard in their implementation of a congestion management application as an example of excellence (See EOE-13 in Appendix E). This wizard is a key component of the congestion management tool for Bonneville Power’s interties.

RTBPTF cites as an example of excellence the use of a real power-voltage (PV) stability analysis tool by FE and MISO that determines system operating limits (See EOE-14 in Appendix E). PV analysis is used to determine the health of the system by determining the rate of voltage decay at a system bus as the level of real power changes because of system loads or transfers across the system.

Section 3.0
Situational Awareness Practices

Introduction

The term “situational awareness” is used numerous times in the blackout reports prepared by NERC and the U.S.-Canada Power System Outage Task Force. The term “situational awareness” is often (and perhaps more accurately) referred to as “situation awareness,” which has been described as having three levels: level 1 is the perception of elements, level 2 is comprehending what those elements mean, and level 3 is using that understanding to project future states.[1] In the context of the blackout reports, the “situational awareness” of operators fits this same definition: knowing what is going on around you and understanding what needs to be done and when to maintain, or return to, a reliable operating state.

Situational awareness is a key concept mentioned in nearly every section of this report. Sections 3.1 through 3.7 focus on elements of situational awareness related to operating practices and procedures rather than to any particular tool. That is, the subsections of this section of the report address the practices, processes, and procedures used by organizations to ensure that their operators have the information and guidance they need to be aware of potentially unreliable system conditions and know what effective actions they can take to maintain reliability.

Practices Addressed in the Report

In preparation for the design of the Real-Time Tools Survey, the results of which are the basis for this report, RTBPTF reviewed the then-current NERC Reliability Standards to identify elements of situational awareness that were addressed to some extent in the standards. Many of these elements that relate to the use of real-time tools are addressed extensively elsewhere in this report. The situational awareness practices section of the Real-Time Tools Survey covered practices and procedures that were identified for investigation to determine whether specific requirements or guidelines should be defined for them. The intent of the recommendations in the following section is to clarify the standards in a way that is enforceable.

The Real-Time Tools Survey and the subsections below address situational awareness practices:

- **Section 3.1, Reserve Monitoring** — a documented set of procedures, practices, or guidelines for maintaining awareness of the current and near-term reactive reserve capability and operating reserve capability (i.e., capability above firm system demand required to provide for regulation, load

[1] Endsley, M. R. 1988. “Situation awareness global assessment technique (SAGAT).” *Proceedings of the National Aerospace and Electronics Conference (NAECON).* New York: IEEE. pp.789-795.

forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserve).

- **Section 3.2, Alarm-Response Procedures** — documented instructions for operators to follow when an alarm is issued. These procedures make operators aware of prudent actions to take in an alarm situation. These procedures should not be confused with Operating Guides, which are discussed in Section 3.4, Operating Guides (Mitigation Plans), of this report.
- **Section 3.3, Conservative Operations** — an operational state resulting from intentional actions in response to unknown, insecure, or potentially risky system conditions to move to a known, secure, and low-risk operating posture. For example, the power system is postured differently for an impending hurricane, ice storm, cold front, etc. These practices are primarily proactive and are usually taken in advance of an anticipated event or system condition, as distinguished from reactive practices, such as those discussed in Section 3.6, System Reassessment and Re-posturing. However, conservative operations practices can be employed following some events and can thus be a subset of reassessment and re-posturing.
- **Section 3.4, Operating Guides (Mitigation Plans)** — written procedures or instructions that identify preventive or remedial actions to be taken by operators to mitigate undesirable pre-contingency or post-contingency conditions on the transmission system. Operating guides help operators be aware of the prudent actions to take under various system conditions. Operating guides should not be confused with the procedures discussed in Section 3.2, Alarm-Response Procedures. An operating guide is a situation-specific, proactive mitigation plan for an undesirable pre-contingency or post-contingency condition on the transmission system, as distinguished from an event-specific, reactive response to a specific alarm. In addition, operating guides should not be confused with operating guidelines which are, in the context of this report, prevalent practices of a general nature that are applicable to many reliability entities, as described in the Introduction to this report.
- **Section 3.5, Load-Shed Capability** — documented practices that define how the system operator is kept aware of the status, availability, magnitude, and time to deploy of all load that can be shed on an emergency basis.
- **Section 3.6, System Reassessment and Re-posturing** — documented practices that give guidance to the system operator for returning the system to a secure and studied condition following an event or events that leave the system in an insecure or unstudied state. These practices are primarily "reactive" in that they are usually performed in response to an event, as distinguished from "proactive" practices, such as the conservative operations practices discussed in Section 3.3, Conservative Operations, of this report, which are primarily used in anticipation of an event or system condition. However, conservative operations practices can be employed following

certain events and can thus be a subset of system reassessment and re-posturing.

- **Section 3.7, Blackstart Capability** — documented practices that define how the system operator is to be kept aware of the status and availability of blackstart generating units and transmission paths identified in the system restoration plan as being essential for restoring the system from a blackout. These practices should not be confused with the plans and procedures required by NERC Reliability Standard EOP-005-0, System Restoration Plans. Typically those plans and procedures deal with longer-term issues such as periodic testing of blackstart units and periodic system restoration drills. The specific practices addressed in this section of the report pertain to the near-term or real-time situational awareness of the current state, availability, and capability of the blackstart facilities.

Significance to the August 14, 2003 Blackout

The *Outage Task Force Final Blackout Report* states that NERC Reliability Standards are based on seven key concepts, one of which is emergency preparedness. Organizations need to have a set of plans and procedures in place in advance of any emergency to ensure that operators are aware of the proper course of action to take and capabilities that are available to them when responding to the emergency. The survey questions discussed in Sections 3.1 through 3.7 were designed to determine the availability and usage of the tools, plans, and procedures necessary for responding to significant system events.

For the most part, the necessary "procedures and capabilities" are addressed in the EOP series of NERC reliability standards. However, the *Outage Task Force Final Blackout Report* specifically identifies problems with each of the items identified in Sections 3.1 through 3.7 of this report.

RTBPTF Recommendations for New Reliability Standards

In Sections 3.1 through 3.7, RTBPTF makes several recommendations to add new requirements to existing standards. These recommendations are summarized below.

- RTBPTF recommends that Reliability Coordination — Current Day Operations requirements be revised to delineate specific, independent requirements for monitoring operating reserves and reactive reserves and that specific, independent measures be developed for these requirements.

- RTBPTF recommends that several existing reliability standards be revised and coordinated to include a requirement that each RC and TOP have documented plans and procedures for conservative operations. These plans and procedures shall identify the credible conditions that could lead to an unknown, insecure, or potentially risky operating state and shall identify the appropriate actions operators are expected to take.

- RTBPTF recommends that all existing standards pertaining to mitigating actions shall be coordinated and revised to require that formal operating guides shall be written for each IROL and any SOL or other condition having a potential impact on reliability. When day-ahead or current-day studies indicate the potential for an operating guide to be implemented, the guide shall be reviewed and verified to still be viable given the studied conditions or shall be updated to provide the appropriate guidance.

- RTBPTF recommends standard EOP-003 be revised to require transmission operators and balancing authorities to provide their operators with information sufficient to give them the location, real-time status (in-service or out-of-service), and real-time MWs of load available to be shed via operator-controlled load-shed capabilities. The task force also recommends that standard IRO-005 be revised to require that RCs have the information needed to quickly ascertain the location, time to implement, and available MWs of load that can be shed in response to a directive.

- RTBPTF recommends that NERC Reliability Standard TOP-004-0, Transmission Operations, be revised to include a requirement for each Transmission Operator and Reliability Coordinator to have formal, documented practices and procedures for the reassessment and re-posturing of its system following an event or events that leave the system in an insecure or unstudied state. This recommendation should be considered along with similar recommendations that are made in Section 3.3, Conservative Operations, of this report.

- RTBPTF recommends that requirement R8 of NERC Standard-EOP-005-0, System Restoration Plans, be revised to specifically state that operators be given the information they need to maintain awareness in real time and on a current-day and day-ahead basis of the availability and capability of the blackstart generation resources and transmission cranking paths identified in their system restoration plans. In addition, this requirement should also require that operators be provided documented practices and procedures that identify the specific information to be monitored to ensure the availability and capability of blackstart resources and to identify the actions to be taken in the event that blackstart availability or capability is less than required in the restoration plan.

Section 3.1
Reserve Monitoring

Definition

Reserve monitoring is a documented set of procedures, practices, or guidelines for maintaining awareness of the current and near-term reactive reserve capability and operating reserve capability.[2]

Background

Operating reserves (also known as real or MW reserves) are used to ensure the energy balance for each BA. They tend to globally impact the electrical system, in contrast to reactive reserves, which tend to be more localized. Figure 3.1-1 shows the various types of operating reserve generation that are defined within the NERC Glossary of Terms.[3] Operating reserves consist of both contingency and regulating reserve.

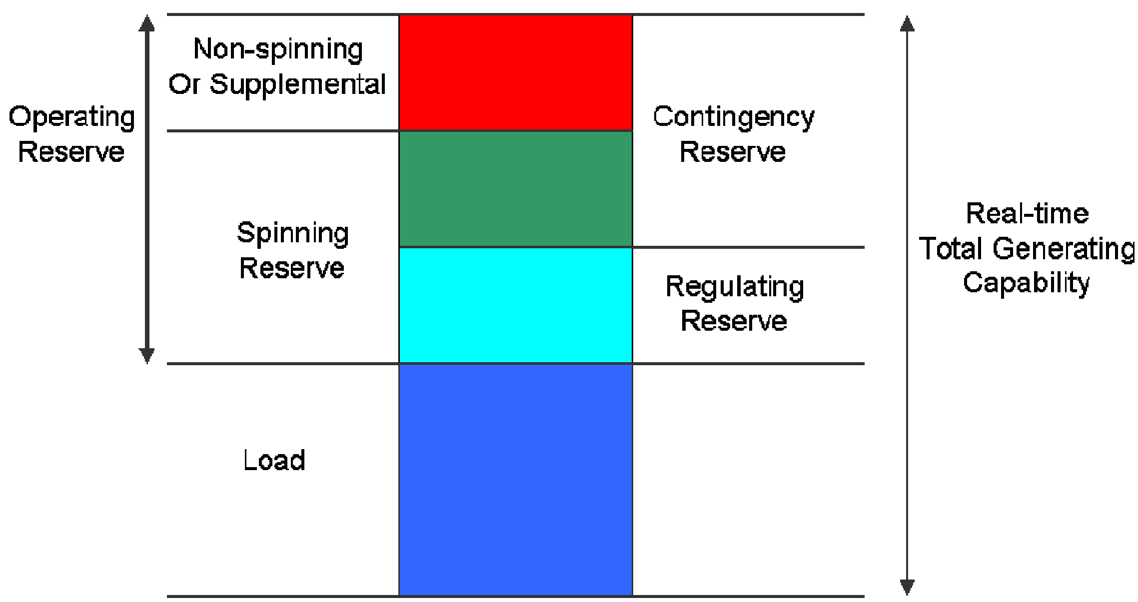

Figure 3.1-1 — Diagram of Reserve Generation, as Defined in NERC Glossary of Terms

[2] Defined as the capability above firm system demand that is required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserve.
[3] http://www.nerc.com

Summary of Findings

General Questions: Reactive Reserves

The survey results indicate that documented operating practices defining how reactive reserves are monitored are commonly used within the industry. Nearly 63 percent (10 out of 16) of RCs and 52 percent (13 out of 25) of TOPs responding to this section of the survey reported having such procedures. Of the entities that do not currently have documented procedures, most indicate they plan to document reactive reserve practices in the future. This includes all of the remaining RCs and the majority of the remaining TOPs. Of those monitoring reactive reserves, all 10 RCs and 12 of 13 TOPs reported that the function was essential or desirable.

Six respondents took the time to comment on the question of reserve monitoring. Five of those commenting concluded that monitoring reactive reserve levels is essential to ensure proper voltage levels and/or provide inputs to further analysis (PV analysis, analysis of interface limits, voltage stability, etc.) and thus help prevent voltage collapse. One respondent with the capability to calculate reactive reserves operates an ancillary service market for reactive reserve capability that calculates margins.

All RCs and TOPs that have documented practices indicated that control room personnel use them. However, other groups rely heavily on the documented practices, including Operations Support Staff at 60 percent of the RCs and 62 percent of the TOPs, as well as Next-Day Planners at 50 percent of RCs and 31 percent of TOPs who responded. First-line management staff also use the capability, but to a lesser degree (0 percent of RCs and 38 percent of TOPs).

Almost all those reporting (more than 80 percent) indicated that the procedures are published. Some use more than one format to document procedures, as shown in Table 3.1-1.

Documentation Format	RCs	TOPs
EMS Help Systems	40%	15%
Web-based Help systems	30%	0%
Departmental memos/letters	30%	54%
EMS Display Notes	50%	69%
Other	10%	8%

Table 3.1-1 — Documented Practices

A variety of groups were reported as being involved in writing and updating procedures. RCs and TOPs indicated that operations support staff are most heavily involved (100 percent for RCs, 46 percent for TOPs) in documentation of procedures. First-line managers are involved in documenting procedures at 30 percent of RCs and 69 percent of TOPs. Control room personnel and next-day planners are also involved in documentation but to a lesser degree (20 percent at RCs and 38 percent at TOPs). In supplemental comments, one company stated that its EMS vendor is involved in documenting procedures.

A large majority of those reporting (90 percent of RCs, 85 percent of TOPs) reported that procedures are reviewed and updated on an as-needed basis. Forty percent of RCs and 38 percent of TOPs reported that procedures are reviewed annually; no respondents reported reviewing more frequently than once per year. One respondent commented that its procedures are reviewed every 2 years, and another indicated that electronic versions of procedures are updated as needed while hard copies are updated annually.

About 70 percent of RCs and TOPs reported that reactive reserve calculations are performed at SCADA scan rates. Much smaller percentages (0 to 10 percent) reported that calculations of reactive reserves are done weekly, daily or hourly. On-demand triggers are used by 20 percent of RCs and 33 percent of TOPs; event triggers are used by 10 percent of RCs but no TOPs. Forty percent of RCs and 17 percent of TOPs reported that the calculation is initiated for “other” reasons, and several commented that the calculation is performed at the state estimator cycle rate.

The following table shows the responses to the question:

Reactive Reserve Factors	RCs	TOPs
Reactive reserve requirements	50%	33%
Nameplate capabilities of static reactive devices	80%	58%
Voltage-adjusted capabilities of static reactive devices	20%	33%
Design "D-curve" var capabilities of generating units	40%	33%
Field tested and proven var capabilities of gen units	60%	50%
AVR status	50%	33%
Zonal deliverability of reactive reserves	20%	8%
Voltage limits	30%	42%
"n-1" criteria (reserve capability following the next contingency)	20%	42%
In-service/out-of-service status of reactive controllers	50%	50%
static Var compensator (SVC) status	40%	25%
LTC regulating range	0%	42%
SVC operating range	40%	25%
Synchronous condenser capability	50%	8%
Effects of neighboring systems	10%	50%
Others	0%	8%

Table 3.1-2 — Factors considered in the Reactive Reserve Calculation

One of 10 RCs and 4 of 12 TOPs indicate that periodic written reports are used to inform operators of the status of reactive reserves. Some of these respondents indicated that the reports are updated annually. These responses indicate a lack of current, near-term awareness of reactive reserve capability in those control centers. However, the majority reported that dynamically updated displays and/or dashboards are used for operator situational awareness, with multi-purpose "dashboards" used by 70 percent of RCs and 42 percent of TOPs and dedicated displays used by 50 percent of RCs and 67 percent of TOPs. One company uses bar graphs to display unit reactive output and capability and another reports that operators are able to generate detailed reactive capability reports on demand.

The majority of respondents with documented practices indicated that operators are primarily made aware of actual reactive reserve margin deficiencies by audible alarms (56 percent of RCs, 67 percent of TOPs) and by color-coded graphical displays (67 percent of RCs, 33 percent of TOPs). Tabular messages and "other'" mechanisms (nomograms, voltage monitoring on contingencies, voltage alarms, etc.) are used to a lesser extent. No one reported using pop-up messages to make operators aware of reactive reserve margin deficiencies.

Operators are made aware of impending reactive reserve margin deficiencies through a variety of means: audible alarms (11 percent of RCs, 67 percent of TOPs); tabular messages (22 percent of RCs, 25 percent of TOPs); color-coded graphical displays (67 percent of RCs, 33 percent of TOPs); and other means, including nomograms, contingency analysis alarms, voltage alarms at key locations, and notification from RTOs (33 percent of RCs, 42 percent of TOPs). No one reported use of pop-up messages to make operators aware of impending reactive reserve margin deficiencies.

Redispatch (90 percent of RCs, 83 percent of TOPs) and reconfiguration of the electric system (90 percent of RCs, 75 percent of TOPs) were the actions most frequently expected to be taken by operators when, per documented procedures, operators are made aware of reactive reserve margin deficiencies. In addition, 40 percent of RCs and 50 percent of TOPs report that personnel are instructed to change voltage schedules to rectify problems. Several respondents (10 percent of RCs, 25 of percent TOPs) also commented that other operator actions are expected, including load shedding, transformer tap adjustments, switching reactors, and increasing reactive output of units when problems are identified. Small percentages of those responding (10 percent of RCs, 8 percent of TOPs) indicate that no actions would be required unless voltage violations were imminent.

General Questions: Operating Reserves

Of 17 RCs and 25 TOPs responding to the survey questions concerning operating reserves, 88 percent of RCs (15) and 76 percent of TOPs (19) have documented practices defining how operating reserves are monitored. Of those that do not have documented procedures, both RCs and 4 of the 8 (50 percent) TOPs indicated that they planned to document procedures in the future. All 15 RCs that having documented and defined operating reserve monitoring practices indicate that the function is “essential” or “desirable” for situational awareness. Nearly all TOPs (18 of 19) with documented practices defining how operating reserves are monitored rated the value of this practice as “essential” or “desirable” for situational awareness.

Several respondents provided written comments on monitoring operating reserves. The comments indicated that monitoring operating reserves is a “prime resource for system reliability” and should be a requirement for all balancing authorities and “maybe” for TOPs. Other respondents noted:

> “Its one of the most important variables the generator dispatcher must be aware of.”

> “…staff needs to know at a glance where operating reserves are available and the amount of reserve available.”

> "Carrying your operating reserves is essential to the reliability of the interconnected transmission system."

Another respondent noted that, in addition to the EMS, operating reserves are tracked by "Market Operation Center web-based reporting tools."

All respondents indicated that control room personnel use operating reserve practices. In addition, about 53 percent of RCs and 33 percent of TOPs reported that next-day planners use the feature. Those reporting also indicate that operations support staff (47 percent of RCs and 61 percent of TOPs) use these practices. More than 30 percent of those reporting indicated that first-line management staff also use the operating reserve practices.

More than 80 percent of those reporting indicate that their operating reserve procedures are published. Some respondents report using more than one format to document procedures, as shown in Table 3.1-3.

Documentation Format	RCs	TOPs
EMS Help systems	20%	22%
Web-based Help systems	27%	17%
Departmental memos/letters	13%	28%
EMS Display Notes	27%	39%
Other	0%	0%

Table 3.1-3 — Formats Used for Documenting Procedures

One respondent clarified that its RTO's written procedures are used for operating reserves.

A variety of groups were reported as involved in writing and updating procedures. RCs and TOPs indicated that operations support staff are most heavily involved (80 percent for RCs, 56 percent for TOPs) in documentation of procedures. First-line management staff are also significantly involved (at 33 percent of RCs and 57 percent of TOPs). Control room personnel are involved in procedure writing and/or updates at only 1 of 15 RCs and 5 of 28 TOPs. Virtually no organizations rely on next-day planners to document operating reserve procedures. Comments reveal that unspecified "reserve groups" or the respondent's RTO or ISO are also involved in documenting operating reserve practices. A large majority of those reporting (100 percent of RCs, 83 percent of TOPs) report that procedures are reviewed and updated on an as-needed basis. Periodic, annual reviews are performed by only 2 of 15 RCs and by 6 of 18 TOPs. No RC reported a periodic review more frequently than once per year; 1 TOP reported a quarterly review/update. One respondent comments that its procedures are reviewed every 2 years.

Eighty percent of RCs and 72 percent of TOPs indicate that operating reserves are calculated at the SCADA scan rate. Smaller percentages of respondents report calculations of operating reserves at less frequent intervals: weekly (7 percent RCs, 0 percent TOPs); daily (13 percent RCs, 11 percent TOPs); and hourly (13 percent RCs, 22 percent TOPs). Additional triggers are also used: on demand (27 percent RCs, 18 percent TOPs); events (13 percent RCs, 6 percent TOPs) and by “others,” such as 4-second, 15-second, 30-second or 5-minute intervals (20 percent RCs, 11 percent TOPs).

Table 3.1-4 illustrates responses to the question regarding which factors are considered in calculating operating reserves.

Operating Reserve Factors	RCs	TOPs
Operating reserve requirements	93%	94%
Seasonal ratings of generating units	60%	61%
Generator reactive loading to maintain voltage schedules	13%	17%
“n-1” criteria (reserve capability following the next contingency)	20%	11%
Historical forced outage rates for generating units	13%	0%
Contributions available from reserve sharing group members	47%	50%
Periodic declared commitments from reserve sharing group members	13%	22%
Firm capacity purchases and sales	47%	78%
Dispatchable load	47%	56%
Quick-start unit capacity	73%	83%
Telemetry	27%	39%
Unit ramp rates	53%	50%
Others	0%	0%

Table 3.1-4 — Factors considered in Operating Reserve Calculation

A clear majority report that operating reserve information is provided to operators via dynamically updated, dedicated displays (73 percent of RCs, 83 percent of TOPs) or dynamically updated, multi-purpose “dashboard” displays for situational awareness (60 percent of RCs, 44 percent of TOPs). Smaller numbers of those responding use periodic written reports (13 percent of RCs, 17 percent of TOPs) to convey information to operators. Only 2 RCs and 1 TOP report using periodic on-line reports. In addition, only 1 RC and 3 TOPs utilize “Other” reporting mechanisms (e.g., SCADA alarms when reserves drop below required levels, unit commitment charts) to convey operating reserve information to operators.

Table 3.1-5 illustrates methods used by the respondents to notify operators of actual deficiencies in operating reserve margins. While tabular messages, pop-up messages and “other” devices are used, operators are most frequently made aware of actual operating reserve margin deficiencies by audible alarms or color-coded graphical displays. The “other” mechanisms used for situational awareness for actual deficiencies include "unit commitment charts," "online reserve monitors and web based tool …," "tabular display with color codes," and "visual indicators on grid wall"). One respondent notes that it has "no alarm, operators monitor," and another comments that "Alarms" are "under development."

Table 3.1-5 also illustrates how respondents make operators aware of impending operating reserve margin deficiencies. RCs and TOPs are likely to report impending deficiencies using color-coded graphical displays, "other" means, or tabular messages; audible alarms are not used as extensively as they are to make operators aware of actual operating reserve deficiencies. Pop-up messages are used by only a small percentage of those reporting. "Other" mechanisms for making operators aware of impending operating reserve deficiencies include unit commitment charts, a capacity assessment tool & EMS displays, tabular display with color codes, broadcasts, posted (web) and phone warnings from ISOs, reserve margins, verbal notification, and a periodic manual evaluation process). As above, one respondent reports "No alarm, operators monitor."

	Actual Operating Reserve Deficiency		**Impending Operating Reserve Deficiency**	
	RCs	**TOPs**	**RCs**	**TOPs**
Audible alarms	47%	61%	8%	35%
Tabular messages	27%	44%	31%	35%
Pop-up messages	7%	17%	8%	12%
Color-coded graphical displays	47%	44%	38%	41%
Others	20%	17%	38%	29%

Table 3.1-5 — Methods of Notifying Operators of "Actual" and "Impending" Operating Reserve Margin Deficiencies

Table 3.1-6 identifies the actions respondents expect operators to take prior to declaring an initial Energy Emergency Alert (EEA-1).The majority of respondents (69 percent of RCs, 89 percent of TOPs) expect operators to recall non-firm sales or redispatch (69 percent of RCs, 67 percent of TOPs) before issuing an EEA-1. Between 30 and 50 percent of RCs and TOPs expect operators to reconfigure the system, enable demand-side management programs for relief, or recall firm sales and/or take other appropriate actions before declaring an EEA-1. Other actions cited in comments included notifying RC and balancing authority; asking for emergency assistance or buying energy in the market; constraining fossil units to maximize total operating reserve; issuing public appeals; sending deployments to bring units on-line; advising various other organizations; constraining generation that has not been offered into the market; requesting voluntary curtailment; curtailing interruptible loads; loading 30 minute (reserves); utilizing all available generation resources; performing supplemental resource evaluations; notifying transmission owners of the possible need for maximum generation; notifying Installed Capacity (ICAP) providers of the possibility of recalling ICAP sales; notifying market participants to activate an emergency demand-response program; and utilizing a reserve-sharing group.

Action	RCs	TOPs
Redispatch	69%	67%
Re-configuration	38%	39%
Recall non-firm sales	69%	89%
Recall firm sales	0%	33%
Demand Side Management	31%	50%
Others	46%	44%

Table 3.1-6 — Actions Operators are Expected to Take Prior to Declaring an EEA-1

Recommendations for New Reliability Standards

Existing NERC reliability standards do not require that operating reserves be calculated or monitored by any entity; entities are only required to have access to and control contingency reserves (BAL-002, R1 and R2) and maintain regulating reserves (BAL-005, R2). RTBPTF recommends that a monitoring requirement be added to the standards to ensure that operators are constantly aware of the available components of operating reserves.

Recommendation – I3

Specify acceptable reactive reserves.

In addition, operating reserves are referenced throughout the standards. In several instances, undefined words are used to refer to a component of operating reserves. This leads to confusion when interpreting the requirements of the standards. Therefore, RTBPTF recommends changes to clarify a term used in the standards.

Recommendation – S16

Require BAs to monitor contingency reserves and calculate contingency reserves at a minimum periodicity of 10 seconds.

RTBPTF Recommendation

To ensure that balancing authorities monitor all of the components of operating reserves, RTBPTF recommends changes to both the contingency and regulating reserve components of the BAL standards. Specifically, RTPBTF recommends that requirement R1 of the BAL-002-0 NERC standard be modified to require that BAs monitor contingency reserves. In addition, the task force recommends a new requirement for the calculation frequency.

PR1. Each Balancing Authority shall ***monitor***, have access to, and/or operate contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

PR2. Each Balancing Authority shall calculate Contingency Reserves at a minimum periodicity of every 10 seconds.[4]

Recommendation – S17

Revise the current-day operations requirements to delineate specific, independent requirements for monitoring operating and reactive reserves

RTPBTF recommends that requirement R2 of NERC standard BAL-005-0 be modified to require that BAs monitor regulating reserves. In addition, the task force recommends a new requirement for the calculation frequency.

PR3. Each Balancing Authority shall ***monitor*** and maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

PR4. Each balancing authority shall calculate Regulating Reserve at a minimum periodicity of every 10 seconds.[5]

[4] To match the update frequency requirement for telemetry data recommended in Section 1.1, Telemetry Data, of this report.

[5] To match the update frequency requirement for telemetry data recommended in Section 1.1, Telemetry Data, of this report.

RTBPTF recommends that requirement R1.4 of IRO-005-2 be modified to refer to Contingency Reserves, to be consistent with the NERC Glossary of Terms.

PR3. System operating (real) and reactive reserves (actual versus required).

Recommendations for Operating Guidelines

Recommendation – G8

Develop a list of the minimum set of items that should be included in the calculations for actual and required operating reserves.

RTBPTF recommends the development of operating guidelines that list the minimum set of items that should be included in the calculations for actual and required operating reserves. These items are listed below:

- Operating reserve requirements
- Facility ratings of generating units (see FAC-008)
- Contributions available from reserve-sharing group members (see BAL-002)
- Firm capacity purchases and sales
- Dispatchable load
- Quick-start unit capacity
- Unit ramp rates

These calculations should be performed at 10-second intervals, and the results should be presented to operators via dynamically updated and dedicated displays, dashboards, or other visualization mechanisms such as those addressed in Section 2.2, Visualization Techniques, of this report.

The task force also recommends that the calculations for actual and required reactive reserves include, at a minimum, the following:

- Nameplate capabilities of static reactive devices
- Field tested and proven var capabilities of generating units
- AVR status
- In-service/out-of-service status of reactive controllers
- Effects of neighboring systems
- Synchronous condenser capability

These calculations should also be performed at 10-second intervals, and the results should be presented to operators via dynamically updated and dedicated displays, dashboards, or other visualization mechanisms, such as those addressed in Section 2.2, Visualization Techniques, of this report.

Areas Requiring More Analysis

RTBPTF did not identify any Areas Requiring More Analysis regarding reserve monitoring.

Examples of Excellence

RTBPTF identified no examples of excellence related to reserve monitoring.

Section 3.2
Alarm-Response Procedures

Definition

Alarm-response procedures are documented instructions that system operators can use to convert alarm data into actionable information. These procedures help system operators know what actions to take in response to a specific alarm.

Background

The *FERC Staff Assessment* identifies a major deficiency in the TOP standards: "While the NERC standards identify the data requirements, they do not identify any minimum acceptable tools and capabilities to turn the data into information necessary to understand critical reliability functions, and therefore the standards lack an important Requirement in this area."[6] This critique applies to many types of system data, but with regard to alarm data, one could argue that alarm-response procedures do convert alarm data into "necessary" information. No NERC reliability standards, however, stipulate specific requirements that would compel RCs, TOPs, or BAs to have documented instructions for operators to follow when an alarm is issued.

Requirement R5 of Standard IRO-002, Reliability Coordination – Facilities, comes close to specifying a requirement for alarm-response procedures when it states that reliability coordinators "shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems . . .." The reference to "alarm management," however, indicates that this requirement is best met by utilizing alarm filtering or other processing methods rather than by having a written response procedure for each alarm.

Requirement R6.6 of Standard TOP-004 requires TOPs to have policies and procedures for responding to IROL and SOL violations. Such violations, which are more serious and complex than many of the alarms typically generated in control centers, are best addressed by specific mitigation plans, which this report refers to "operating guides." Alarm-response procedures are not to be confused with operating guides, which are discussed in Section 3.4, Operating Guides (Mitigation Plans), of this report. The recommendations in Section 3.4 address the concerns that FERC staff raised about providing operator guidance for mitigating undesirable pre- or post-contingency conditions on the transmission system.

Alarm Tools (Section 2.1), Alarm-Response Procedures (this section), and Operating Guides (Mitigation Plans) (Section 3.4) are all used extensively throughout the industry.

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[6] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. Page 103. www.ferc.gov/indus-act/reliability/standards.asp.

These complementary tools should be implemented in a coordinated fashion to maximize an operator's situational awareness, standardize and simplify expected operator actions, and facilitate operator access to reference materials that support the decision-making process. In addition to the procedures discussed in the above-listed sections, the alarm-processing methods (such as alarm filtering) discussed in Section 2.1, Alarm Tools, of this report may prove practical in converting alarm data into actionable information. The alarm-response procedures section of the Real-Time Tools Survey evaluates one component of the integrated set of tools an operator should have for converting alarm data into actionable information.

Summary of Findings

Real-Time Tools Survey responses indicate that industry members commonly use alarm-response procedures. More than 70 percent (32 out of 45) of the respondents to this section of the survey report having documented procedures to inform operators of prudent actions to take in an alarm situation. This number includes 63 percent (10 out of 16) of responding RCs. Almost all (31 out of 32) of those who use documented alarm-response procedures find them an "essential" or "desirable" tool for maintaining situational awareness. A few respondents comment on the value of these procedures, for instance: "With the hundreds of alarms that our SCADA and other systems produce, having a useable, understandable alarm procedure is a must."

Another respondent states, "The response to most alarms is fairly straightforward and does not require a specific written procedure. A written procedure is helpful for those few alarms that require the dispatcher to follow through a more complex response, such as arming special protection schemes or initiating curtailment procedures." Only 2 of the 13 respondents that have no documented alarm response procedures report plans to add such procedures, indicating an apparent lack of perceived need for them. Perhaps some entities have more informative ways of displaying alarm data, and perhaps some control centers lack adequate resources for developing and maintaining alarm-response procedures.

Documentation of Procedures

The survey explored the ways in which alarm-response procedures are documented. Nearly all respondents (27 out of 31) retain procedures in the form of published documents. In addition, 58 percent (18 out of 31) have such procedures available via at least one quick-access method such as Web-based help, EMS display notes, or online help systems. Table 3.2-1 summarizes the responses to this question. The results for "online help systems (EMS)" are similar to the results noted in Section 2.1, Alarm Tools, regarding the availability/functionality of help features in the alarm tools application.

Documentation of Alarm Response Procedures	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Other	Total
Published procedures	X	X	X	X	X	X	X	X	X	X								17	**27**
Online help systems (EMS)						X												6	**7**
Web-based help systems (other)						X	X			X								1	**4**
Departmental memos/letters		X		X			X	X		X								11	**16**
EMS display notes (e. g., notes on substation one-line displays)		X		X		X												9	**12**

Table 3.2-1 — Documentation of Alarm-Response Procedures

Need for Quick Access

Two respondents emphasize the need for quick access to documented procedures. One respondent comments, “Because of the large amount of documentation for reliability coordinators, better use of SCADA reference pages should be explored to allow the operator convenient display of related documents/procedures.” Another respondent expands on this topic, as follows:

> EMS ‘on screen’ procedure identifiers are key examples of best practice operations. Unusual events and conditions requiring operator action are often specific to a particular station, plant, line, etc. Procedure identifiers become ‘quick reference’ tools that assist in precise real-time decision-making. Example: solar magnetic disturbances (SMD) – by utilizing alarm response procedures for a SMD we can view established limits and identify correct actions to be taken to protect specific transformers.

Although this last comment may blur the distinction between alarm-response procedures and operating guides (discussed in Section 3.4, Operating Guides (Mitigation Plans)), it emphasizes the importance of ensuring that guidance is available quickly to operators whenever significant levels of information must be processed under stressful circumstances.

Recommendations for New Reliability Standards

The survey responses do not justify developing a recommendation for a new requirement to mandate a written response procedure for all the types of alarms that can be generated in a control center. As one respondent points out, many alarms can be dealt with in a straightforward manner; documented guidance is helpful only when complex situations arise. In addition to alarm-response procedures, other alarm-processing methods that are discussed in Section 2.1, Alarm Tools, of this report (such as alarm filtering) may prove to be practical ways to convert alarm data into actionable information for operators.

Recommendation – G9

Provide written alarm response procedures via at least one quick access method such as Web-based help or on-line help system.

Recommendations for Operating Guidelines

Based on survey responses, RTBPTF recommends that an operating guideline be developed to encourage providing operators (when requested) with written alarm response procedures that are usable, understandable, and available via at least one quick-access method such as Web-based help, EMS display notes, or an online help system. RTBPTF recommends that the method for accessing the procedures be tied directly to the alarm tools application. That is, when an operator receives an alarm, the alarm entry itself should provide a direct method (e.g., by clicking on an icon on the entry) to access the response procedure pertaining to that alarm.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for alarm-response procedures.

Examples of Excellence

RTBPTF identified no examples of excellence for alarm-response procedures.

Section 3.3
Conservative Operations

Definition

Conservative operations encompass actions taken in response to unknown, insecure, or potentially risky system conditions in order to move to a known, secure, and low-risk operating posture. Undertaking conservative operations produces a known, baseline condition in the face of unknown or insecure conditions, thereby enhancing system reliability. Conservative operations produce an operating state in which system operators can be confident and from which they can better focus their preparations for worsening conditions or contingent events. System operators employ conservative operations, for example, to posture a power system in response to an impending hurricane, ice storm, or cold front.

Conservative operating practices are primarily proactive, taken in advance of an anticipated event or system condition, as distinguished from reactive practices such as the reassessment and re-posturing practices described in Section 3.6, System Reassessment and Re-posturing, of this report. Conservative operations practices, however, can be employed following certain events and thus can be a subset of reassessment and re-posturing practices, as noted in Section 3.6.

Background

Requirement R4 of NERC Reliability Standard TOP-004-0, Transmission Operations, states that, "If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes." Requirement R5 of NERC Standard TOP-001-0, Reliability Responsibilities and Authorities, requires TOPs to inform their RCs and other affected entities of real-time or anticipated emergency conditions and to take actions to avoid or mitigate those situations. Neither standard establishes performance measures for those requirements or otherwise gives guidance on acceptable compliance. Having documented practices for conservative operations would promote confidence and consistency in the actions operators take to avoid or mitigate threatening conditions or events.

Summary of Findings

Survey results reveal that most respondents have documented practices for identifying and responding to situations that call for initiating conservative operations. Several survey respondents offer testimonials regarding the value of conservative operations practices, such as the respondent who comments that because of such practices, "Consistency among system operators is greatly enhanced." Another respondent states, "It is essential that operators have documented procedures to follow to prepare for impending risky or insecure operating states." One respondent eloquently expresses why conservative operations practices are essential:

> A conservative operation stance puts the system at a known baseline state when there is a high probability of events (or a sequence of events) occurring that are not normally covered by operating within the reliability criteria. Starting at an unstressed, known operating point gives system operators the time to determine what has happened and what actions to take.

Respondents report having documented a range of actions to effect conservative operations. Because there currently is no requirement to have documented practices or procedures for conservative operations, the task force recommends that a subset of the most prevalent and effective procedures uncovered by the survey be formalized into required practices. The new requirement should identify events that call for conservative operations and stipulate the appropriate, event-specific control actions (or means of developing appropriate control actions) for enacting conservative operations.

Documentation of Practices

Most survey respondents report having documented practices for conservative operations. A little more than half of the respondents to this section of the survey (24 out of 46), including 75 percent (12 out of 16) of RC respondents, report having some type of documented practices for identifying conditions under which the system must be moved toward a more conservative operating state and that also describe the actions the system operator is expected to take. Of the respondents who have such documented practices, two-thirds (16 out of 24) consider them "essential" for guiding operator actions. Almost all (23 out of 24) retain such documentation in the form of published procedures. Of the RCs who report having documented practices for conservative operations, 67 percent (8 out of 12) consider them "essential" for situational awareness, and one-third (4 out of 12) consider them "desirable."

A few respondents report other, apparently supplemental, means of documenting practices for conservative operations. Table 3.3-1 identifies the various ways in which respondents document conservative operations practices.

Documentation of Conservative Operations	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	Others	Total
Published procedures	X	X	X	X	X	X	X	X	X	X	X	X					11	**23**
Web-based help systems	X	X	X	X		X											3	**8**
Departmental memos	X		X		X												5	**8**
Online help systems (EMS)	X	X															2	**4**
EMS display notes (e.g., one-line notes)																	2	**2**

Table 3.3-1 — Documentation of Conservative Operations Practices[7]

Conditions that Trigger Conservative Operations

The survey explored what conditions or events would cause the 24 respondents who report having documented practices to implement conservative operations (see Table 3.3-2). A few RCs report a wide range of triggering events, as do a few TOPs and BAs who are not also RCs. Most respondents identify several triggers, which the task force recommends be included in an operating guideline (see Recommendations for New Operating Guidelines later in this section).

[7] RC responses are indicated with “X.” Aliases are used as column headers to mask the RC’ names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, “RC 1” in any given table is not the same as “RC 1” or the equivalent identifier in another table in this report.

Conditions Triggering Conservative Operations	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	Others	Total
Weather events (e.g., severe storms, floods, or temperature extremes)	X	X	X	X	X	X	X	X	X	X	X					11	**22**
Natural threats to facilities (e.g., forest fires or earthquakes)	X	X	X	X	X	X	X	X	X	X		X				9	**20**
Terrorist threats or sabotage	X	X	X	X	X	X	X	X								7	**15**
Solar magnetic disturbances	X			X		X	X	X		X						3	**9**
Loss of multiple transmission lines, resulting in insecure operations	X	X	X	X	X				X							6	**12**
Unexpected capacity shortfall	X	X	X	X							X	X				7	**13**
Loss of multiple generating units, as through shutdown of a nuclear plant	X	X	X		X						X					5	**10**
Loss of situational awareness (e.g., major loss of telemetry data)	X	X	X	X		X										8	**13**
Voltage degradation in another system	X		X				X		X							5	**9**
Cyber security threats	X	X		X	X											6	**10**
Major loss of load	X				X											7	**9**

Table 3.3-2 — Conditions Triggering Conservative Operations

Documented Actions to be Taken

The survey inquired about what actions are documented as being required or recommended for the system operator to take in response to triggering conditions. The intent of these questions was to determine what is expected of operators when they discover a real-time or potential condition that could cause the system to enter an unknown, insecure, or unreliable operating state. In addition to the tabulated responses summarized in Table 3.3-3, several respondents comment that they take steps to acquire or schedule additional generating capacity and reactive reserves. A few RCs report a wide range of expected operator actions, as did a few TOPs and BAs who are not also RCs. The task force recommends that several of the specific actions that many respondents employ be included in a new operating guideline. As some respondents point out, which actions are appropriate depends on the nature of the current or impending situation.

Documented Actions for Conservative Operations	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC 13**	**RC 14**	**RC15**	**Others**	**Total**
Cancel planned outages	X	X	X	X	X	X	X	X		X	X	X				9	**20**
Lower transfer limits	X	X	X	X	X	X	X	X	X			X				5	**15**
Increase coordination and communication of relevant information	X	X	X	X	X			X		X	X					8	**16**
Perform analysis of multiple contingencies or other credible disturbances	X	X	X		X				X			X				6	**12**
Initiate a “heavy load” voltage procedure (e.g., pre-switch capacitors)	X	X	X					X			X					3	**8**
Staff the backup control center	X					X	X			X						5	**9**
Curtail transfers	X	X	X		X											6	**10**
Use more conservative thermal limits				X			X		X							3	**6**
Reduce ATCs or bring them to zero				X		X										3	**5**

Table 3.3-3 — Documented Actions for Conservative Operations

Recommendations for New Reliability Standards

Requirement R4 of NERC Reliability Standard TOP-004-0, Transmission Operations, states that a situation in which a TOP “enters into an unknown operating state” is considered an emergency. Requirement R5 of NERC Standard TOP-001-0, Reliability Responsibilities and Authorities, requires TOPs to inform their RC and other affected entities of real-time or anticipated emergency conditions and to take actions to avoid or mitigate those conditions. Neither standard establishes performance measures for those requirements or otherwise provides guidance on acceptable compliance.

Recommendation – S18

Establish document plans and procedures for conservative operations.

RTBPTF Recommendations

The RTBPTF recommends that a requirement be added to Standard TOP-001-0 to address plans and procedures for conservative operations. RTBPTF's first proposed requirement (PR) related to conservative operations is given below.

PR1. Each reliability coordinator and transmission operator shall have documented plans and procedures for conservative operations that identify the conditions that credibly could lead to an unknown, insecure, or potentially risky operating state. The plans and procedures, which shall be made available to the entity's operators, shall identify the appropriate actions operators are expected to take to move the electric system to a known, secure, and low-risk operating posture.

RTBPTF developed the following proposed measure (PM) for the proposed requirement above.

PM1. Each reliability coordinator and transmission operator shall document plans and procedures for conservative operations and shall demonstrate the use of those plans and procedures.

RTBPTF also recommends that requirement R4 of NERC Reliability Standard TOP-004-1 be revised to refer to the plans and procedures proposed in PR1 above and to clarify that it is the transmission system (not the operator) that can actually enter into an unknown (to the operator) operating state. RTBPTF's second PR for conservative operations is as follows:

Recommendation – S19

Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes.

PR2. Any situation in which the transmission system for which a transmission operator is responsible enters an unknown operating state (i.e., any state for which operating limits have not been determined) shall be considered to be an emergency. The transmission operator shall restore system operations to respect proven, reliable limits within 30 minutes. The transmission operator shall restore the system based on the plans and procedures for conservative operations stipulated in PR1 of TOP-001-0.

RTBPTF developed the following PM for the proposed requirement above:

PM2. Whenever the transmission system for which a transmission operator is responsible enters an unknown operating state, that transmission operator shall have and upon request provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that can be used to determine whether it restored operations to respect proven, reliable system limits within 30 minutes, in accordance with documented plans and procedures for conservative operations specified in requirement R4.

These recommendations should be considered at the same time as similar recommendations made in Section 3.6, System Reassessment and Re-posturing, of this report.

Rationale

The survey reveals that industry members commonly use documented practices for conservative operations. Current reliability standards that require action in response to an unknown or unreliable operating state lack specificity. The standards should be reinforced by requiring documented practices for conservative operations. Conservative operations produce an operating state in which system operators can be confident and from which they can better focus their preparations for worsening conditions or contingent events. Having documented practices for conservative operations enhances system reliability and promotes consistency in operator guidance and in the actions operators take to avoid or mitigate threatening conditions or events.

Recommendation – G10

Specify the system conditions for initiating conservative operations and action plans to follow during conservative operations.

Recommendations for New Operating Guidelines

The task force recommends that an operating guideline be developed in support of the new requirements for conservative operations proposed above. The operating guideline should stipulate, at a minimum, that the following system conditions should trigger conservative operations:

- Weather events such as severe storms, floods, temperature extremes, or ice (as relevant to the reliability area)

- Natural threats, such as forest fires, volcanoes, or earthquakes (as relevant to the reliability area)
- Terrorist threats or sabotage
- Solar magnetic disturbances (for applicable latitudes)
- Loss of multiple transmission lines, resulting in insecure operations
- Unexpected shortfall in capacity
- Loss of multiple generating units, such as the shutdown of a nuclear plant
- Loss of situational awareness (e.g., major loss of telemetry data or major failure of a critical real-time tool)
- Cyber security threats
- Major loss of load
- Voltage degradation

RTBPTF further recommends that an accompanying operating guideline be developed that, at a minimum, specifies the following operator actions to be taken (as appropriate) if it is necessary to initiate conservative operations.

- Cancel planned outages
- Lower transfer limits
- Increase coordination and communication of relevant information
- Perform analysis of multiple contingencies or other credible disturbances
- Curtail transfers

Alternatively, these operating guidelines may be incorporated in the revised standards recommended above if the standard drafting team and industry response deem that inclusion appropriate.

Areas Requiring More Analysis

RTBPTF recommends no additional areas of analysis for conservative operations.

Examples of Excellence

RTBPTF identified no examples of excellence related to conservative operations.

Section 3.4
Operating Guides (Mitigation Plans)

Definition

Operating guides, also called mitigation plans, are written procedures that identify appropriate preventive or remedial actions that operators should take to mitigate undesirable pre- or post-contingency conditions on the transmission system. An operating guide is a situation-specific, proactive mitigation plan to avoid or repair an undesirable condition, rather than an event-specific, reactive response. Operating guides are vital for providing operators with an understanding (in all appropriate time frames) of the control actions they have available to respond to the types of vulnerabilities and risks that their system studies identify.

Operating <u>guides</u> are not to be confused with operating <u>guidelines</u>, which are, in the context of this report, general practices prevalent at many reliability entities. The NERC glossary defines three other terms that may add to the confusion: operating plan, operating process, and operating procedure. RTBPTF, however, did not find those terms used in any current standards.

Background

Several NERC reliability standards address the need for procedures to direct system operators in mitigating or resolving reliability problems. No standard, however, addresses operating guides in a comprehensive manner that identifies successful control actions. For example, requirement R3 of Standard IRO-005, Reliability Coordination – Current Day Operations, states that RCs are to "initiate control actions or emergency procedures" to resolve IROL violations, but it does not specify a minimally acceptable procedure and even seems to imply that emergency procedures are optional. Neither requirement R3 nor requirement R5 of the same standard, which contains almost identical language, establishes performance measures.

In addition, requirements R6 and R6.6 of Standard TOP-004, Transmission Operations, direct transmission operators to "develop, maintain, and implement formal policies and procedures to provide for transmission reliability," including "responding to IROL and SOL violations." Again, however, the requirements neither establish specific performance measures nor identify minimally acceptable procedures.

The *FERC Staff Assessment* notes that the TOP group of standards:

> …does not require that the system be assessed to the same extent in the day ahead planning analysis, nor does it require identification of control actions, implementable within 30 minutes, that are needed to bring the system back to a stable state in order to withstand the next contingency without cascading. This may present a potential vulnerability as operators may not be aware of available control actions or worse may not have control actions, other than firm load

shedding, available to them to adjust the system to a stable state after it incurs its first contingency. This can lead to poor execution and reliability risk after the first contingency has occurred in real-time operations.[8]

This deficiency can be rectified by establishing both appropriate control actions and the time frame in which the system should be assessed to ascertain whether control actions are needed. Requirement R4 of Standard TOP-008, Response to Transmission Limit Violations, addresses time frames somewhat by requiring transmission operators to mitigate SOL violations based on assessments preformed "in all operating time frames." This requirement, however, does not specify whether it applies to day-ahead planning, provides no measures, and does not address control actions or other aspects that the survey found that operating guides tend to include.

Control actions are addressed minimally in requirement R3 of Standard TOP-007, Reporting SOL and IROL Violations. This requirement directs TOPs to "take all appropriate actions" to return the system to within the acceptable bounds of an IROL or SOL. In addition, requirement R4 of this standard directs reliability coordinators to "evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits." Both requirements establish only minimal measures, none of which address the need to develop control actions ahead of time and to document expected actions.

Requirement R17 of Standard IRO-005, Reliability Coordination – Current Day Operations, also compels RCs to evaluate the actions taken to return the system to within the acceptable bounds of an IROL. As with requirement R4 of TOP-007, however, requirement R17 neither establishes any measures nor addresses the need to develop control actions ahead of time and document those expected actions.

Standard IRO-004, Reliability Coordination – Operational Planning, comes closest to addressing the deficiency FERC staff identifies in the TOP standards. Requirement R3 of this standard directs RCs to work with TOPs and BAs to "develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs." Although this requirement addresses control actions and applies to day-ahead studies, it neither stipulates performance measures nor addresses the need to document expected actions.

In addressing the context and preconditions for the blackout of August 14, 2003, Chapter 4 of the *Outage Task Force Final Blackout Report*[9] discusses the adequacy of

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[8] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. p. 102. www.ferc.gov/indus-act/reliability/standards.asp

[9] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April. Chapter 4.

system studies intended to identify mitigating actions that operators can take to avoid endangering reliability under current-day conditions. Specifically, the report states that:

> Reliability coordinators and control areas prepare regional and seasonal studies for a variety of system-stressing scenarios, to better understand potential operational situations, vulnerabilities, risks, and solutions. However, the studies FirstEnergy relied on—both by FirstEnergy and ECAR—were not robust, thorough, or up-to-date. This left FE's planners and operators with a deficient understanding of their system's capabilities and risks under a range of system conditions.[10]

The report goes on to describe the lack of documented mitigation plans or procedures: "The investigation team could not find FirstEnergy contingency plans or operational procedures for operators to manage the FirstEnergy control area and protect the Cleveland-Akron area from the unexpected loss of the Perry plant."[11]

This section examines operating guides as one component of an integrated set of tools designed to convert data into actionable information. The procedures described in Section 2.1, Alarm Tools, Section 3.2, Alarm-Response Procedures, and the current section are used extensively throughout the industry. As noted in Section 3.2, these complementary tools should be implemented in a coordinated fashion in order to maximize each operator's situational awareness, standardize and simplify expected operator actions, and facilitate access to reference materials that support the decision-making process.

Summary of Findings

The Real-Time Tools Survey results indicate that industry members generally utilize operating guides. Exactly 100 percent (45 out of 45) of the respondents to the operating guides section of the survey report having documented procedures for mitigating undesirable conditions on the transmission system. This number includes 100 percent (16 out of 16) of the responding RCs. More than 82 percent (31 out of 32) of the respondents who report using documented operating guides rate them as "essential" for situational awareness. This number includes 15 of the 16 responding RCs. A few survey respondents offer opinions, generally favorable, regarding the value of operating guides, as demonstrated by the following quotations:

> "Operating guides are a necessary tool to define the limitations of the power system, provide guidance on indications of instability [or] other impending problems, and provide guidance for mitigating actions."

> "Operating guides are necessary for quick and efficient mitigation of operational problems."

[10] Ibid. p. 39.
[11] Ibid. p. 42.

“Operating guides are truly essential to the reliability of the interconnect. Without operating guides, operating decisions in a neighboring area could cause reliability concerns in another area.”

Users of Operating Guides

Table 3.4-1 summarizes the types of users of operating guides associated with individual RCs and totals the users associated with all other respondents.

Users of Operating Guides	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Control room personnel	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		NR	27	**42**
Next-day planners	X	X	X	X	X	X	X	X	X	X	X	X	X				NR	7	**20**
Operations support staff	X	X	X	X	X		X	X	X								NR	15	**23**
First-line management staff	X	X	X	X	X	X										X	NR	14	**21**
Others	X																NR	1	**2**

Table 3.4-1 — Users of Operating Guides[12]

Writers of Operating Guides

The survey asked who is responsible for writing and updating operating guides. The results, summarized in Table 3.4-2, reveal that the next-day planners associated with RCs are more involved with writing and updating operating guides than is the case for other respondents. Operations support staff and first-line management are heavily involved for all respondents. The involvement of next-day planners in writing operating guides is related to an issue raised in the *FERC Staff Assessment,*[13] which is discussed in depth in the Background subsection above.

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[12] Reliability coordinator responses are indicated with “X.” Aliases are used as column headers to mask the RCs’ names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, “RC 1” in any given table is not the same as “RC 1” or the equivalent identifier in another table in this report.

[13] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation’s Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

Writers of Operating Guides	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Operations support staff	X	X	X	X	X		X	X	X	X	X	X	X	X		X	NR	19	**33**
Next-day planners	X	X	X	X	X	X	X			X							NR	6	**14**
First-line management staff	X	X	X	X	X	X		X									NR	19	**26**
Control room personnel	X	X				X											NR	9	**12**
Others									X						X		NR	5	**7**

Table 3.4-2 — Writers of Operating Guides

Some respondents indicate that they write or coordinate operating guides in conjunction with various stakeholders, such as market participants. One respondent stated that, “The Security Coordinator actively develops mitigation plans for potential or actual operating events in conjunction with all regional operating entities. All of these plans are discussed on the regional hotline, allowing all regional entities to be involved in and aware of proposed actions in resolving SOL/IROL violations.”

Formats for Operating Guides

The survey explored the various formats in which operating guides are documented. Table 3.4-3 summarizes the responses. The guides of more than 90 percent of respondents to this question (41 out of 45) are in the form of published documents. In addition, approximately 55 percent (25 out of 45) of respondents have operating guides available via at least one quick-access method such as Web-based help, EMS display notes, or online help systems. The need for ready access to operating guides is discussed in the Recommendations for New Reliability Standards subsection below.

Format of Operating Guides	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**RC17**	**Others**	**Total**
Published procedures	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	25	**41**
Online help systems (EMS)	X			X	X	X		X				X					NR	5	**11**
Web-based help systems (other)	X	X	X	X	X	X					X			X			NR	3	**11**
Departmental memos/letters	X	X	X			X	X		X				X				NR	13	**20**
EMS display notes (e. g., notes on substation one-line displays)	X	X	X		X		X	X	X	X							NR	9	**17**
Others				X													NR	1	**2**

Table 3.4-3 — Format of Operating Guides

Structure of Operating Guides

The survey asked respondents how operating guides are structured. Table 3.4-4 summarizes the responses. A preponderance of respondents (42 out of 45) have specific operating guides that address specific conditions; only about 58 percent of respondents (26 out of 45) have guides for general conditions. Operating guides appear to focus equally on preventive and remedial actions. RCs in particular indicate flexibility in how they structure operating guides.

Structure of Operating Guides	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Specific guides for specific conditions	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	26	**42**
Generic guides for general categories of conditions	X	X	X	X	X	X	X	X	X	X	X	X			X		NR	13	**26**
Guides focused on preventive actions (pre-contingency)	X	X	X	X	X	X	X	X	X	X	X	X	X	X		X	NR	18	**33**
Guides focused on remedial actions (post-contingency)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		NR	20	**35**
Others																	NR	0	**0**

Table 3.4-4 — Structure of Operating Guides

Focus of Guides

The survey asked about the conditions for which entities have developed operating guides. Table 3.4-5 summarizes the responses and shows that most entities have guides for a wide range of conditions.

Focus of Operating Guides	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Violations of thermal limits	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		NR	25	**40**
Violations of voltage magnitude limits	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		NR	18	**33**
Specific topology configurations	X	X	X	X	X	X	X	X	X	X		X			X		NR	18	**30**
Conditions triggering a special protection scheme	X	X	X	X	X	X	X	X	X			X	X	X			NR	13	**25**
Violations of transfer limits	X	X	X	X	X	X	X	X	X	X	X		X				NR	16	**28**
Violations of power angle limits	X	X	X	X	X	X											NR	3	**9**
Others											X						NR	2	**3**

Table 3.4-5 — Focus of Operating Guides

Documented Actions to be Taken

Key to any operating guide is the set of control actions that it instructs the system operator to take. Table 3.4-6 summarizes survey responses concerning what operator actions the operating guides stipulate. These responses reveal that operating guides contain a wide range of control actions, with most respondents employing the fundamental actions of redispatch, reconfiguration, transaction curtailment, and load shedding.

Documented Actions to be Taken	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Redispatch on-line generation	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	25	41
Reconfigure transmission facilities	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	22	**38**
Shed load	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	22	**38**
Curtail transactions	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	16	**32**
Switch shunt reactive devices	X	X	X	X	X	X	X	X	X		X	X					NR	14	**25**
Change voltage schedules	X	X		X	X	X	X	X	X	X	X	X	X				NR	10	**22**
Commit or de-commit units	X	X	X	X	X	X	X	X	X		X		X	X	X		NR	8	**21**
Arm SPS	X	X	X	X	X	X						X	X	X	X		NR	8	**18**
Change LTC taps	X	X	X	X				X		X							NR	8	**14**
Notify other entities (e.g., RCs, nuclear stations)	X	X	X	X	X	X			X		X						NR	6	**14**
Change phase-angle regulating (PAR) taps	X	X	X	X			X			X		X					NR	3	**10**
Change control of DC line or FACTS device	X		X		X		X							X			NR	1	**6**
Others								X		X							NR	0	**2**

Table 3.4-6 — Documented Actions to be Taken

Recommendations for New Reliability Standards

The Real-Time Tools Survey responses reveal that many entities have operating guides that both identify appropriate control actions and are developed and updated based on assessments made in appropriate time frames. There remains, however, a need to formally stipulate performance measures and time frames because, as discussed in the Background subsection of this report, although several NERC reliability standards describe procedures for mitigating or resolving reliability problems, none of them addresses this issue in a comprehensive manner that establishes clear and measurable requirements. The standards fail to specify minimally acceptable procedures or performance measures.

The standards should identify both control actions and the time frame in which the system should be assessed to ascertain whether control actions are needed. Current requirements that address control actions establish, at best, only minimal measures and fail to address the need to develop actions ahead of time and document the expected actions in operating guides. Although requirement R3 of Standard IRO-004, Reliability Coordination – Operational Planning, addresses control actions and applies to day-ahead studies, the requirement stipulates no performance measures and fails to address the need to document expected actions in operating guides.

The standards and requirements described in the Background subsection above should be consolidated and expanded to add clarity, substance, and measurability so that all RCs and TOPs understand they must develop, coordinate, maintain, and implement operating guides that identify preventive or remedial actions to mitigate undesirable pre- or post-contingency conditions on the transmission system.

Operating guides are vital to providing operators with an understanding (in all appropriate time frames) of the control actions available to them to respond to the types of vulnerabilities and risks that adequate system studies can identify.

Recommendation – S20

Develop formal operating guides (mitigation plans) and measures for each IROL and any SOL or other conditions having a potential impact on reliability.

RTBPTF Recommendations

RTBPTF recommends that the following requirements in the NERC TOP reliability standards be consolidated or closely coordinated and cross-referenced in order to clearly, completely, and uniformly spell out all requirements and measures for developing and evaluating control actions to mitigate SOL and IROL violations or other undesirable conditions on the transmission system:

- TOP-004, requirement R3
- TOP-004, requirements R6 and R6.6
- TOP-007, requirements R3 and R4
- TOP-008, requirement R4

In addition, RTPBTF recommends that the following IRO requirements be consolidated or closely coordinated and cross-referenced in order to clearly, completely, and uniformly spell out all requirements and measures for developing and evaluating control actions to mitigate SOL and IROL violations or other undesirable conditions on the transmission system:

- IRO-004, requirement R3
- IRO-005, requirements R3, R4, and R17

RTBPTF further recommends that the consolidated or coordinated requirements be expanded to include the following proposed requirements (PRs):

PR1. Formal operating guides shall be written for every IROL, SOL, or other condition, identified in regional or inter-regional planning studies, seasonal assessments, or other near-term operating studies, that could affect reliability.

Recommendation – S21

Review and update operating guides (mitigation plans) when day-ahead or current day studies indicate the potential need to implement an operating guide.

PR2. When day-ahead or current-day studies indicate the potential need to implement an operating guide, that operating guide shall be reviewed and either verified as still viable for the studied conditions or updated to provide the guidance appropriate to the studied conditions.

Recommendation – S22

Provide temporary operating guides (mitigation plans) with control actions for situations that could affect reliability but that have not been identified previously.

PR3. Temporary, less formal operating guides, which primarily identify control actions, shall be written and provided to operators for situations, identified in day-ahead or current-day studies, that could affect reliability but that have not been identified or formally documented previously.

Recommendation – S23

Develop joint operating guides (mitigation plans) for situations that could require more than one RC or more than one TOP to execute actions

PR4. Operating guides for situations that could require that more than one reliability coordinator direct control actions or more than one transmission operator execute actions shall be jointly developed by all reliability coordinators and transmission operators responsible for directing or executing the control actions.

Recommendation – S24

Develop a formal procedure to document the processes for developing, reviewing, and updating operating guides (mitigation plans).

PR5. A formal procedure shall document the processes for developing, reviewing, and updating operating guides.

Recommendation – S25

Incorporate verifiable and traceable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates when modifying operating guides (mitigation plans).

PR6. Those who modify documented operating guides shall follow a procedure that incorporates verifiable and trackable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates.

Recommendation – S26

Write operating guides (mitigation plans) in clear, unambiguous language, leaving nothing to interpretation.

PR7. Operating guides shall be written in clear, unambiguous language, leaving nothing to interpretation.

Recommendation – S27

State the specific purpose of existence for each operating guide (mitigation plan).

PR8. Each operating guide shall state the specific purpose of (or reason for) its existence.

Recommendation – S28

Summarize the specific situation assessment and address the method of performing the assessment in each operating guide (mitigation plan).

PR9. Each operating guide shall summarize the specific assessment of the situation it addresses including the method of performing the assessment.

PR10. The situations assessed shall include, but are not limited to, the following:

- Violations of thermal limits
- Violations of voltage magnitude limits
- Specific topology configurations
- Conditions that trigger a special protection scheme
- Violations of transfer limits
- Violations of power angle limits

Recommendation – S29

Identify all appropriate preventive and remedial control actions in each operating guide (mitigation plan).

PR11. Operating guides shall identify all appropriate preventive and remedial control actions, including, but not limited to, the following:

- Redispatching on-line generation
- Reconfiguring transmission facilities
- Shedding load
- Curtailing transactions
- Switching shunt reactive devices
- Changing voltage schedules
- Committing or de-committing units
- Arming an SPS
- Changing LTC taps
- Notifying other entities (e.g., reliability coordinators, nuclear stations)
- Changing PAR taps
- Changing control of DC line or FACTS device

Recommendation – S30

Develop criteria in operating guides (mitigation plans) to support decisions regarding whether a specific control action should be taken.

PR12. Operating guides shall include decision-support criteria when operators must decide whether a specific control action should be taken.

Recommendation – S31

Incorporate on-line tools that utilize on-line data when operating guides (mitigation plans) require calculations.

PR13. Operating guides that require the operator to perform calculations shall incorporate online tools that utilize online data.

Recommendation – S32

Make operating guides (mitigation plans) readily available via a quick-access method such as Web-based help, EMS display notes, or on-line help systems.

PR14. Operating guides shall be readily available to operators via a quick-access method such as Web-based help, EMS display notes, or online help systems.

RTBPTF recommends that the following proposed measures (PMs) be established for the requirements presented above.

PM1. Each Reliability Coordinator and Transmission Operator must demonstrate a documented procedure for developing, reviewing, and updating operating guides.

PM2. Each Reliability Coordinator and Transmission Operator must demonstrate the operation of all guides and verify that they include all required elements.

PM3. Each Reliability Coordinator and Transmission Operator must demonstrate that operating guides are readily accessible to on-shift operators.

PM4*.* Each Reliability Coordinator and Transmission Operator must demonstrate how the operator will perform the calculations required for any operating guide.

PM5*.* Each Reliability Coordinator and Transmission Operator must demonstrate the logic of any decision-support criteria in the operating guides.

Rationale

As discussed above, the *Outage Task Force Final Blackout Report*[14] and the *FERC Staff Assessment*[15] both emphasize the need for operators to understand control actions available for mitigating undesirable operating conditions or situations on the transmission system. NERC standards currently identify various vague and uncoordinated requirements for procedures, appropriate actions, and action plans to respond to IROL and SOL violations. A unifying standard applicable to all operating guides will provide structure and clarity regarding performance and compliance with the various requirements. All survey respondents already have documented procedures of some sort to guide the operator in mitigating undesirable conditions on the transmission

[14] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April.
[15] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

system. The recommendations and measures proposed above will establish formal, baseline requirements for operating guides that will raise the bar for many reliability entities.

Recommendations for New Operating Guidelines

RTBPTF does not recommend developing operating guidelines for operating guides.

Areas Requiring More Analysis

RTBPTF recommends no additional areas of analysis for operating guides.

Examples of Excellence

RTBPTF identified no examples of excellence related to operating guides.

Section 3.5
Load-Shed Capability

Definition

The Energy Information Administration of the U.S. Department of Energy defines load shedding as the "Intentional action by a utility that results in the reduction of more than 100 megawatts (MW) of firm customer load for reasons of maintaining the continuity of service of the reporting entity's bulk electric power supply system. The routine use of load control equipment that reduces firm customer load is not considered to be a reportable action."[16]

Having the capability to shed electrical load requires knowing the status, availability, magnitude, and time-to-deploy of all load that can be shed on an emergency basis. Operating practices related to awareness of real-time load-shed capability are those documented practices that define how the system operator is kept informed of the status, availability, magnitude, and time-to-deploy of all load that can be shed quickly.

Background

The *Outage Task Force Final Blackout Report* concludes that, had 1,500 MW of load been shed manually or automatically within the Cleveland-Akron area before the outage of the Sammis-Star 345-kV line, the August 2003 blackout could have been averted.[17] In its technical analysis of the blackout, NERC identifies a corrective action to be taken by FE that includes developing the capability to reduce load (by any method or combination of methods) in the Cleveland-Akron area by 1,500 MW within 10 minutes of a directive from FE's RC to do so.[18] To be able to deliver such a response at any time, the TOP must be apprised of the status, availability, magnitude, and time-to-deploy of all load that can be shed by any method or methods. An ongoing awareness of load-shed capability is needed to give all RCs, TOPs, and BAs confidence in their ability to shed load in an emergency situation. Reliability standards, however, do not specify that operators must be given the information needed to maintain situational awareness of their load-shed capability.

NERC Reliability Standard EOP-001-0, Emergency Operations Planning, requires TOPs and BAs to develop, maintain, and implement load-shedding plans. Operators are not, however, required to maintain situational awareness of the probable results of implementing such plans under real-time or developing operating conditions.

NERC Reliability Standard EOP-003-0, Load Shedding Plans, requires TOPs and BAs to have plans for performing operator-controlled, manual load sheds. The standard also requires that

[16] http://www.eia.doe.gov/glossary/glossary_l.htm
[17] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April. p. 70.
[18] *Technical Analysis of the August 14, 2003, Blackout*: *What Happened, Why, and What Did We Learn?* A report to the NERC Board of Trustees by the NERC Steering Group. July 13 2004. p. 117.

those plans be implementable "in a time frame adequate for responding to the emergency." The standard does not establish a performance measure for this requirement. The *FERC Staff Assessment* found that a major problem with the EOP standards is the failure to specify the amounts and time frames for load shedding capability.[19] FERC staff mentions this deficiency specifically in regard to EOP-003-0[20] and EOP-001-0, about which they state, "load shedding is the option of last resort and must be capable of being implemented in a much shorter time period than 30 minutes."[21] Standards are clearly needed to establish the amounts and time frames for load shedding capability, although those issues are beyond the scope of the Real-Time Tools Survey.

Standard EOP-003-0 also contains requirements pertaining to implementing automatic load shedding via UFLS or UVLS relays, but operators are not required to maintain situational awareness of the availability or effectiveness of those devices or facilities.

Even if requirements regarding amounts and time frames for load shedding capability existed, however, how would an RC know whether the desired response to a directive to shed load could be achieved under real-time operating conditions? And how would the TOP or BA know that it could respond adequately to such a directive? NERC standards give RCs the authority to direct TOPs and BAs to shed load, and those entities are required to comply with such directives. Currently, however, no standards require any of the entities to maintain awareness of their capabilities to shed load under real-time operating conditions.

Summary of Findings

The load-shedding capability section of the Real-Time Tools Survey was intended to assess current operator practices related to maintaining awareness of load-shed capability and ability to utilize that capability in an emergency. Although most survey respondents report having documented practices for maintaining awareness of load-shed capability, the information they monitor varies greatly, as do the actions identified for shedding load. In addition, few respondents report monitoring any aspect of situational awareness of automatic load-shedding devices, either UVLS or UFLS relays.

Documentation of Practices

Survey respondents generally have documented practices for maintaining awareness of load-shed capability. Approximately 74 percent of respondents (34 out of 46) report having some type of documented practices for this function. Of those who have documented practices, more than 66 percent (23 out of 34) consider them "essential" to situational awareness. Current load-shed capability appears to be documented most thoroughly among TOPs,

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[19] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp. p. 42.
[20] Ibid. p. 51.
[21] Ibid. p. 50.

including the RCs who are also TOPs, probably because in most situations only the TOP has direct control over load-shed capability. Table 3.5-1, identifies the types of documentation respondents have regarding their load-shed practices.

Documentation of Load-Shed Practices	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**Others**	**Total**
Published procedures	X	X	X	X		X	X	X	X	X	X	X					18	**29**
Online help systems (EMS)	X	X			X		X	X									5	**10**
Departmental memos			X	X	X												8	**11**
Web-based help systems	X	X	X	X					X								3	**8**
EMS display notes (e.g., one-line notes)	X			X	X	X											10	**14**

Table 3.5-1 — Documentation of Load-Shed Practices[22]

Load-Shed Information Monitored

The survey explored ways in which system operators keep informed of the status of factors related to their load-shed capability (see Table 3.5-2). As a whole, respondents who are TOPs appear to monitor a wide range of information, as do RCs who are also TOPs and 2 RCs who are not TOPs. One RC reports that its system operators monitor the sensitivity factors of load-shed capability on any facilities that are in violation of thermal, reactive, or transfer limits. A few RCs report a much narrower scope of monitored information, and some did not respond to this question.

Load-Shed Information Monitored	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**Others**	**Total**
Control status (availability of load-shedding field equipment)	X	X	X	X	X	X	X	X									9	**17**
Calculated or estimated MW subject to operator-controllable load shedding	X	X	X	X	X	X		X									18	**25**
Control status (availability of load-shed tools)	X	X			X	X	X										15	**20**

[22] Reliability coordinator responses are indicated with "X." Aliases are used as column headers to mask the RCs' names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, "RC 1" in any given table is not the same as "RC 1" or the equivalent identifier in another table in this report.

Load-Shed Information Monitored	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	Others	Total
Calculated or estimated MW available from voltage reduction	X	X							X	X	X						4	**9**
Measured feedback of actual load shed following load-shedding/restoration actions	X	X	X	X													9	**13**
Status of SCADA communication link for operator-controllable load shedding	X	X	X		X												12	**16**
Calculated or estimated MW that can be shed within specific time frames (e.g., < 5 min. or < 1 hr)				X		X						X					6	**9**
Measured, calculated, or estimated MW subject to operator-controllable load shedding as a percentage of peak load			X						X								6	**8**
Measured, calculated, or estimated MW subject to operator-controllable load shedding as a percentage of real-time load	X																5	**6**
Calculated or estimated cold-load pickup of shed load			X														4	**5**
Calculated or estimated load recovery rates following a voltage reduction										X							8	**9**

Table 3.5-2 — Load-Shed Information Monitored

In response to survey questions related to automatic load shedding, only 5 RCs report monitoring any aspect of UFLS relays. Three RCs monitor the status, location, and set points of UFLS relays, and 4 monitor, in one manner or another, the amount of load subject to UFLS operations. RCs report monitoring even fewer aspects of UVLS relays. Perhaps these RCs have few (or no) UVLS relay schemes in their reliability areas.

Similarly, few entities who are not RCs (that is, TOPs, BAs, or other respondents) report that their system operators monitor situational capability of UFLS relays. Only 10 respondents report that their operators monitor the status, location, and set points of UFLS relays. Similarly, only 10 respondents monitor, in one manner or another, the amount of load subject to UFLS operations. To put the awareness of UFLS relays into perspective, fewer than half of all respondents (26 out of 55) provide responses to the UFLS relay question, and only about half of those who respond report that their system operators monitor anything related to UFLS relays.

Documented Actions to Be Taken

The survey asked what documented actions system operators are expected to take when load-shed capability is inadequate. These questions were intended to identify what operators are expected to do when they realize (before load shed is needed) that a current lack of available resources or facilities will prevent operator-controlled load-shedding schemes from yielding the hoped-for results. Table 3.5-3 summarizes the responses. The low number of responses might indicate that, industry wide, this issue has not been given much consideration. A few respondents make comments to the effect that if load shed were implemented and the desired results were not achieved, then an attempt would be made to shed additional load.

Expected Actions for Inadequate Load-Shed Capability	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	Others	Total
Notify management	X	X	X	X	X	X	X										13	**20**
Expedite any maintenance activities affecting load-shed capability	X			X	X	X	X	X	X								7	**14**
Dispatch switching personnel to non-SCADA stations to stand by	X	X	X	X	X			X									8	**14**
Notify other entities (e.g., RCs)	X	X	X	X	X	X											11	**17**
Request engineering studies for additional options	X	X	X					X									8	**12**

Table 3.5-3 — Expected Operator Responses to Inadequate Load-Shed Capability

Recommendation – I4

Determine adequate load-shed capability.

Recommendations for New Reliability Standards

All RCs, TOPs, and BAs need confidence in their ability to shed load in an emergency situation, which means they need to be continuously aware of their load-shed capability. Reliability standards, however, do not specify that operators must be given the information needed to maintain situational awareness of load-shed capability.

As noted in the Background section above, NERC Reliability Standard EOP-001-0, Emergency Operations Planning, requires TOPs and BAs to develop, maintain, and implement load-shedding plans. There is, however, no requirement for operators to maintain situational awareness of the probable results of implementing the plans under current or developing operating conditions. In addition, NERC Reliability Standard EOP-003-0, Load Shedding Plans, requires TOPs and BAs to have plans for operator-controlled, manual load shed. The standard requires that these plans be capable of being implemented "in a timeframe adequate for responding to the emergency." The standard, however, does not specify a measure for this requirement.

NERC standards currently assign RCs the authority to direct their TOPS and BAs to shed load, and TOPs and BAs must comply with such directives. No standard, however, specifies that any of these entities must maintain awareness of their capability to shed load under current operating conditions.

Standard EOP-003-0 also contains requirements pertaining to plans for implementing automatic load shedding via UFLS or UVLS relays but does not specify the need for operator awareness of the status of the devices or facilities supporting those plans.

The lack of specific load-shedding directives should be addressed by new requirements in the EOP group of reliability standards.

Recommendation – S33

Provide the location, real-time status, and MWs of load available to be shed.

RTBPTF Recommendation

The RTBPTF recommends that requirements be added to Standard EOP-003-0 to address operator awareness of current load-shedding capability. RTBPTF's proposed requirements (PR) related to load-shedding capability are as follows:

PR1. Each transmission operator and balancing authority shall provide their operators with information sufficient to give them the location, set points, real-time status (in service or out of service), and actual MW of load-shed capability (measured, calculated, or estimated) from the automatic load-shedding schemes (UFLS or UVLS relays) that are installed within the transmission operator's or balancing authority's footprint.

PR2. Each transmission operator and balancing authority shall provide their operators with information sufficient to give them the location, real-time status (in service or out of service), and real-time MW of load available to be shed via the operator-controlled load-shedding capabilities (including voltage reduction) that they are required to be able to implement within an “adequate” time frame.

RTBPTF developed the following proposed measures (PMs) for the proposed requirements above.

PM1. Each transmission operator shall demonstrate via documented procedures, real-time visualization tools, or other dynamically updated media readily accessible to operators, the static and dynamic information provided to operators to fulfill requirement PR1.

PM2. Each transmission operator shall demonstrate via documented procedures, real-time visualization tools, or other dynamically updated media readily accessible to operators, the static and dynamic information provided to operators to fulfill requirement PR2.

Requirement R3 of NERC Standard IRO-005-0, Reliability Coordination – Current Day Operations, stipulates that RCs must “ensure [that] all resources, including load shedding, are available to address a potential or actual IROL violation.” The standard contains no performance measures for this requirement. Because RCs have the authority and responsibility to direct (and ensure the availability of) load shedding, they also should be continuously aware of the number of MW that they can expect will be shed as a result of their directives to shed load by operator-controlled actions, including voltage reduction. In addition, they should be aware of the expected performance of UFLS or UVLS relays in response to abnormal system conditions. The most effective way to ensure this awareness would probably be to delegate responsibility for it to the TOPs and BAs, who would then keep the RC informed.

RTBPTF recommends that a requirement be added to Standard IRO-005-0 to address the need to keep RCs informed of load-shedding capabilities.

PR3. Each reliability coordinator shall be able to ascertain quickly, using information provided by the transmission operators and/or balancing authorities in their footprint (or by other means), the location, time to implement, and available MW of load that can be shed in response to a directive or that can be expected to be shed as a result of an abnormal system frequency or voltage event. Updates should be prepared at a minimum on a by-exception basis, and verifications should be performed at least daily.

RTBPTF recommends the following measure for PR3.

PM3. Each reliability coordinator shall have documented procedures for ascertaining the current load-shed capability of the transmission operators and balancing authorities in his area of responsibility. The reliability coordinator shall maintain a log of the updates made to the information regarding load-shed capability and the verification of that information.

Rationale

Reliability standards related to load-shedding capability are vague and lack specific requirements for providing operators with the information they need to maintain awareness of their load-shed capability under current and developing system conditions. Standard IRO-005, for example, requires RCs to "ensure" the availability of load shedding. This requirement is unachievable unless RCs maintain situational awareness sufficient to engender ongoing confidence that a directive to shed load can be fulfilled. Standard EOP-003 requires transmission providers and BAs to have the capability to shed load in an "adequate" time frame. This requirement is unachievable unless operators have sufficient situational awareness to engender ongoing confidence that they can respond successfully to a directive to shed load.

Many factors underscore the need for the requirements and measures recommended above. These include the failure to take proactive steps to shed load to avert the blackout of August 14, 2003, the FERC staff's assessment that requirements are needed for the amounts and timing of load-shedding capability, the vague load-shed requirements in the reliability standards, and the findings of the Real-Time Tools Survey.

Recommendations for Operating Guidelines

RTBPTF does not recommend developing operating guidelines for awareness of real-time load-shed capability.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for awareness of load-shedding capability.

Examples of Excellence

RTBPTF cites a load-shedding/rotation and voltage reduction application used by Dominion Virginia Power as an example of excellence (See EOE-15 in Appendix E). This application enhances reliability and situational awareness by allowing quick response to a load-shed directive and overview monitoring of load shed facility availability and expected response.

Section 3.6
System Reassessment and Re-posturing

Definition

Reassessment and re-posturing of an electrical transmission system entail control actions that return the system to a secure and studied condition following one or more events, such as an overload, that place the system in an insecure or unstudied state. Control actions associated with reassessment and re-posturing of a system include identifying, evaluating, and correcting. Documented operating practices related to reassessment and re-posturing of a system are primarily reactive in that they usually are performed in response to an event.

Reassessment and re-posturing should be distinguished from proactive practices, such as the conservative operations practices discussed in Section 3.3, Conservative Operations, of this report, which are used primarily in anticipation of an event or system condition. Because conservative operations practices can also be employed following certain events, however, they can form a subset of practices related to reassessment and re-posturing of a system, as indicated in Table 3.6-2 below and in the subsequent recommendations.

Background

Chapter 7 of the *Outage Task Force Final Blackout Report* includes an examination of causal factors common to all major outages during the past 40 years.[23] One cause common to several events (including the August 14, 2003 blackout) is that some operators performed "no reassessment of system conditions following the loss of an element and [no] readjustment of safe limits."[24] The report goes on to repeat the following recommendation from past events: "Following a contingency, the system must be returned to a reliable state within the allowed readjustment period. Operating guides must be reviewed to ensure that procedures exist to restore system reliability in the allowable time periods."[25]

The current NERC reliability standards closely related to this recommendation are limited in scope and specificity. Some fail to address reassessment and readjustment, and others fail to require documentation of necessary procedures.

Requirement R6 of NERC Reliability Standard TOP-004-0, Transmission Operations, requires that TOPs have formal policies and procedures that provide for transmission reliability. Several subrequirements of R6 identify the activities those policies and procedures should address, but none specifically includes the reassessment and re-posturing of a system following an event or events that leave the system in an insecure

[23] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April. pp. 107–110.
[24] Ibid. p.108.
[25] Ibid.

or unstudied state. Although subrequirement R6.6 comes close, it refers only to responding to IROL or SOL violations. Other situations may require a system to be reassessed or re-postured. For example, requirement R4 of Standard TOP-004-0, Transmission Operations, states that a situation in which a generating or transmission facility “enters into an unknown operating state” is to be considered an emergency, and operations must be restored “to respect proven reliable power system limits within 30 minutes.” This requirement, however, does not specify the need for documented procedures.

Requirement R17 of NERC Standard IRO-005-1, Reliability Coordination—Current Day Operations, requires RCs to evaluate the impacts of an SOL or IROL violation and decide whether the actions being taken are appropriate and sufficient. Of all the requirements in this standard, R17 comes closest to addressing reassessment and re-posturing, but its scope is limited to SOL and IROL violations. It also does not require that RCs have documented practices or procedures for the prescribed evaluations and determinations. This deficiency in the IRO standard is the same as the one discussed above in relation to the TOP standards.

The *FERC Staff Assessment* notes that the TOP group of standards:

> …does not require identification of control actions, implementable within 30 minutes, that are needed to bring the system back to a stable state in order to withstand the next contingency without cascading. This may present a potential vulnerability as operators may not be aware of available control actions or worse may not have control actions, other than firm load shedding, available to them to adjust the system to a stable state after it incurs its first contingency. This can lead to poor execution and reliability risk after the first contingency has occurred in real-time operations. [26]

Summary of Findings

The reassessment and re-posturing section of the Real-Time Tools Survey evaluates the prevalence and types of documented actions to be taken to reassess and re-posture a system following an event or events that render it insecure or unstudied. Survey results reveal that a majority of respondents have documented practices related to reassessing and re-posturing their systems. The results also reveal that respondents have documented a range of actions for reassessing and re-posturing the system.

Documentation of Practices

The survey responses reveal that industry members generally possess documented practices for reassessment and re-posturing of their systems. Approximately 61

[26] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation’s Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp. p.102.

percent of respondents to this section of the survey (28 out of 46), including 88 percent (14 out of 16) of the RCs who responded, report having some type of documented practices that guide the operator in reassessing and re-posturing the system.

More than 78 percent (22 out of 28) of those who have documented practices consider them “essential” for guiding operator actions and maintaining system reliability. Of the RCs who report having such documented practices, 93 percent (13 out of 14) consider them “essential” for situational awareness and the remaining RC considers them “desirable” for situational awareness. These results represent an impressive endorsement of the necessity for these practices.

All respondents who have documented practices (28 out of 28) have them in the form of published procedures. A few report one or more other, apparently supplemental, means of documenting practices for reassessing and re-posturing the system. Table 3.6-1 identifies the ways in which practices are documented.

Documentation of Reassessment and Re-posturing Practices	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**Others**	**Total**
Published procedures	X	X	X	X	X	X	X	X	X	X	X	X	X	X			14	**28**
Web-based help systems	X		X	X	X			X		X							1	**7**
Departmental memos		X	X	X		X	X		X								5	**11**
Online help systems (EMS)	X	X															2	**4**
EMS display notes (e.g., one-line notes)	X																3	**4**

Table 3.6-1 — Documentation of Reassessment and Re-posturing Practices[27]

Several respondents’ comments indicate that entities employ various methods for categorizing and presenting these practices. In several control centers, the practices are incorporated into various separate but related procedures rather than being captured in a single procedure or set of procedures specific to the topic. More than 90 percent of respondents (26 out of 28) report having specific guides for specific conditions, and more than two-thirds (19 out of 28) report having generic guides for general categories of conditions. Seventeen respondents have both. Half of the respondents (14 out of 28) indicate that their documented guides are in the form of checklists of actions to be taken. How the documentation is structured or categorized may not be important, but the necessity of having such documentation is summed up by one respondent as follows: “Guidance and procedures for calculating new reliable

27 Reliability coordinator responses are indicated with “X.” Aliases are used as column headers to mask the RCs’ names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, “RC 1” in any given table is not the same as “RC 1” or the equivalent identifier in another table in this report.

operating limits, redispatch of generation, communication and notification, etc., are necessary when operators [are] assessing and responding to unplanned events."

Documented Actions to be Taken

The survey also inquired about the tasks, functions, or other actions specified in the documented practices of the 28 respondents who report having them. Table 3.6-2 summarizes the responses. Some RCs report having a comprehensive set of documented actions, as do some TOPs and BAs who are not also RCs. Several actions that are taken by a majority of respondents should be included in an operating guideline for the industry as a whole.

Documented Actions for Reassessment and Re-posturing	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	Others	Total
Communicate and coordinate with neighboring systems	X	X	X	X	X	X	X	X	X	X		X				11	**22**
Verify situational awareness	X	X	X	X	X			X	X		X					8	**16**
Initiate conservative operations	X	X	X	X	X	X	X		X							10	**18**
Verify data availability	X	X	X	X			X	X			X					8	**15**
Reassess, recalculate, or reverify SOLs	X	X	X	X		X				X						5	**11**
Reassess, recalculate, or reverify IROLs	X	X	X	X		X				X						5	**11**
Verify tool availability	X	X	X	X							X					5	**10**
Assess voltage stability	X	X			X							X				5	**9**
Assess transient stability	X				X											2	**4**
Assess dynamic stability	X															2	**3**

Table 3.6-2 — Documented Actions for Reassessment and Re-posturing

Recommendations for New Reliability Standards

Because there currently is no requirement for documented practices or procedures related to reassessment and re-posturing, RTBPTF recommends that a subset of the most prevalent and appropriate procedures revealed by the Real-Time Tools Survey be formalized into required practices.

As noted in the Background subsection above, the *Outage Task Force Final Blackout Report* underscores that, "Following a contingency, the system must be returned to a reliable state within the allowed readjustment period. Operating guides must be reviewed to ensure that procedures exist to restore system reliability in the allowable time periods"[28] and the current NERC reliability standards that closely relate to this recommendation either fail to address reassessment and readjustment or fail to require documentation of necessary procedures. Requirement R17 of NERC Standard IRO-005-1, Reliability Coordination – Current Day Operations, comes closest to addressing reassessment and re-posturing, but its scope is limited to SOL and IROL violations, and it does not require documented practices or procedures. The FERC Staff Assessment also calls for documented practices and procedures for reassessing and re-posturing a system.

Recommendation – S34

Establish documented procedures for the reassessment and re-posturing of the system following an event.

RTBPTF Recommendations

RTBPTF recommends that NERC Reliability Standard TOP-004-0, Transmission Operations, be revised to include a requirement that each transmission operator and reliability coordinator have formal, documented practices and procedures for the reassessment and re-posturing of the system following an event or events that leave the system in an insecure or unstudied state. RTBPTF further recommends that NERC Standard IRO-005-1, Reliability Coordination—Current Day Operations, be revised to include a requirement that reliability coordinators have formal, documented practices and procedures to evaluate whether the actions being taken by transmission operators are effective responses to the event or events that left the system in an insecure or unstudied state. These documented practices should also address appropriate control actions if the evaluation indicates that the transmission operator's response is ineffective or insufficient. The goal of these practices is to help operators identify appropriate control actions (or means of developing appropriate control actions) for reassessment and re-posturing of the system.

RTBPTF recommends that the requirement below be added to Standard TOP-004-0 to establish procedures for reassessment and re-posturing of the system following an event or events that place the system in an insecure or unstudied state. This recommendation should be considered along with similar recommendations made in Section 3.3, Conservative Operations, of this report. RTBPTF's proposed requirement (PR) related to reassessment and re-posturing of a system is as follows:

PR1. Each reliability coordinator and transmission operator shall create and maintain formal, documented practices and procedures for the reassessment and re-

[28] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 108.

posturing of its system following an event or events that leave the system in an insecure or unstudied state.

RTBPTF developed the following proposed measure (PM) for the proposed requirement above:

PM1. Each reliability coordinator and transmission operator shall demonstrate the performance of its documented practices and procedures for the reassessment and re-posturing of its system by conducting a simulation of an event that leaves the system in an insecure or unstudied state or by providing operator logs and other records and reports of actions taken following an actual event.

RTBPTF also recommends that a new requirement be added to Standard IRO-005-1 to address the RC's reassessment of the system.

PR2. Each reliability coordinator shall create and maintain formal, documented practices and procedures related to reassessment of its system to evaluate the appropriateness of the actions being taken by transmission operators in the reliability coordinator's footprint following an event or events that leave the system in an insecure or unstudied state. These documented practices and procedures shall also address appropriate control actions or re-posturing of the system in case the reliability coordinator's evaluation indicates that the transmission operator's actions are inappropriate or insufficient.

PM2. Each reliability coordinator shall demonstrate the performance of its documented practices and procedures for evaluating whether the actions being taken by transmission operators in the reliability coordinator's footprint are appropriate by conducting a simulation of an event that leaves the system in an insecure or unstudied state or by providing operator logs and other records and reports of actions taken in response to an actual event.

Rationale

Failure to adequately reassess and re-posture the transmission system following contingency events has been one of the causes common to several major, historical outages, including the blackout of August 14, 2003. The proposed recommendations above, which will add scope and specificity to current reliability standards, are necessary to provide operators with the information and guidance they need to perform reassessment and re-posturing. The *FERC Staff Assessment* of the TOP series of standards supports these recommendations. The Real-Time Tools Survey findings establish that documented procedures for reassessing and re-posturing the transmission system following a contingency event are prevalent within the industry. The recommendations proposed above will establish formal, uniform requirements for documented and demonstrable practices and procedures that will raise the bar for many reliability entities.

Recommendation – G11

Communicate and coordinate with neighboring systems for reassessing and re-posturing a system following an event that places the system in an insecure or unstudied state following an event that places the system in an insecure or unstudied state.

Recommendations for Operating Guidelines

RTBPTF recommends that an operating guideline be developed in support of the new requirements recommended above for reassessing and re-posturing the electric system. At a minimum, the following tasks, functions, and other actions should be included in the recommended policies and procedures:

- Communication and coordination with neighboring systems
- Verification of situational awareness
- Conservative operations (discussed in Section 3.3, Conservative Operations, of this report)
- Verification of data availability
- Verification of tool availability
- Reassessment, recalculation, or reverification of SOLs
- Reassessment, recalculation, or reverification of IROLs
- Identification of appropriate control actions or specific methodologies for developing appropriate control actions

Alternatively, this operating guideline may be incorporated in the revised standards recommended above if the standard-drafting team and industry deem that inclusion appropriate.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for system reassessment and re-posturing.

Examples of Excellence

RTBPTF cites the development of documented guidelines to address events on the transmission system that are outside the scope of established operations by the Virginia Carolinas (VACAR) South Subregion of SERC Reliability Corporation (SERC) as an example of excellence (See EOE-16 in Appendix E). These guidelines, which are part of the *VACAR-South Reliability Coordinator Handbook*, are intended for use by the RC working in close coordination with the BAs (TOPs) within the reliability area, and includes several examples of what to include in a procedure for reassessing and re-posturing the system following an event or events that leave the system in an insecure or unstudied state.

Section 3.7
Blackstart Capability

Definition

Blackstart generators can operate without an external power source. They are designed to provide power to critical transmission pathways after a blackout so that other critical generators can be restarted. Operating practices related to blackstart capability define how a system operator maintains awareness of and responds to the condition of blackstart generating units and transmission paths identified in the system restoration plan as being essential for restoring power after a blackout.

Background

The *Outage Task Force Final Blackout Report* states that, "to deal with a system emergency that results in a blackout,…there must be procedures and capabilities to use 'black-start' generators (capable of restarting with no external power source) and to coordinate operations in order to restore the system as quickly as possible to a normal and reliable condition."[29] NERC Reliability Standard EOP-005-0, System Restoration Plans, requires each TOP to have a plan for re-establishing its electric system in the event of a partial or total shutdown. Among other things, restoration plans must evaluate the reliable capability of blackstart generation resources and the "cranking" transmission paths needed to deliver those resources to other generating units, which will be started subsequently in accordance with the restoration plan. Most of the requirements of this standard concern long-term activities such as annual review and update of the plan, periodic testing, and annual simulation.

The standard contains a requirement (R8) that each TOP shall "ensure the availability and location of blackstart capability within its area to meet the needs of the restoration plan." Although this requirement does not specify the time frame to which it applies, an argument can be made that it must apply to near-term or real-time awareness of the condition of blackstart facilities. It stands to reason that, once having identified blackstart generation resources and key transmission paths, TOPs must not inadvertently compromise their ability to implement system restoration plans by neglecting to maintain day-ahead, current-day, or real-time awareness of the condition of the blackstart facilities.

The practices examined here are not to be confused with practices required by NERC Reliability Standard EOP-005-0, System Restoration Plans. These NERC practices generally concern long-term activities such as periodic testing of blackstart units and periodic system restoration drills. The practices addressed in this section pertain to near-term or real-time awareness of the state, availability, and capability of a system's blackstart facilities.

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[29] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April. p.10.

The blackstart capability section of the Real-Time Tools Survey addresses the prevalence of and methods for documenting and monitoring real-time blackstart conditions and responding to a lessening or loss of blackstart capability.

Summary of Findings

Survey respondents generally have documented practices regarding blackstart capability, but it is clear from the survey results that more specific guidance and requirements are needed in this area.

Documentation of Monitoring Practices

Survey responses reveal that industry members generally possess documented practices for maintaining awareness of blackstart capability. Approximately 63 percent of respondents (27 out of 43) report having documented practices for maintaining awareness of blackstart capability. This figure includes 75 percent (12 out of 16) of RCs who responded. More than 80 percent (23 out of 27) of those who have documented practices consider them “essential” for situational awareness. This figure includes 69 percent (11 out of 16) of the responding RCs.

All (27 out of 27) those with documented practices have them in the form of published procedures. Table 3.7-1 identifies the types of documentation that respondents maintain monitoring blackstart capability.

Documentation of Procedures for Monitoring Blackstart Capabilities	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**Others**	**Total**
Published procedures	X	X	X	X	X	X	X	X	X	X	X	X					15	**29**
Web-based help systems	X	X	X	X				X									1	**6**
Departmental memos	X	X				X											7	**10**
EMS display notes (e.g., one-line notes)					X		x										3	**5**
Online help systems (EMS)			X														2	**3**

Table 3.7-1 — Documentation of Procedures for Monitoring Blackstart Capabilities[30]

Information Monitored

The survey inquired about the specific information that operators monitor in order to maintain awareness of current blackstart capabilities. Table 3.7-2 summarizes the responses. All but 2 of the respondents included in the “Others” column of the table represent TOPs. The responses summarized in this column indicate that TOPs monitor a wide variety of information, as do many RCs who are also TOPs. It may be that TOPs monitor such a wide range of information because, in most cases, only the TOP has direct responsibility for and control over a system restoration plan that utilizes blackstart generation to energize key transmission paths. Several RCs report monitoring a narrower scope of information, and others did not respond to this question.

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[30] Reliability coordinator responses are indicated with “X.” Aliases are used as column headers to mask the RCs’ names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, “RC 1” in any given table is not the same as “RC 1” or the equivalent identifier in another table in this report.

Blackstart Information Monitored	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	Others	Total
On-line/off-line status of blackstart units	X	X	X	X	X	X	X	X	X	X	X					20	**31**
Scheduled return-to-service dates for outaged blackstart units	X	X	X	X	X	X	X	X	X	X						16	**26**
Derated capacity of blackstart units	X	X	X		X	X	X	X	X	X						12	**21**
Status of transmission lines on alternative pathways	X	X	X	X	X		X	X	X	X						16	**25**
Scheduled return-to-service dates for outaged transmission lines in critical system restoration paths	X	X	X	X	X	X	X		X							15	**23**
Status of SCADA communication links to blackstart units and switchyards	X	X	X	X				X		X						15	**21**
AVR status of blackstart units	X	X	X		X											9	**13**
Fuel availability for blackstart units	X	X		X		X										10	**14**
Status of remote/local control switches for blackstart units	X	X														14	**16**

Table 3.7-2 — Blackstart Information Monitored

Actions to be Taken

The survey inquired about what documented actions system operators are expected to take when blackstart capability is found to be inadequate, i.e., when a blackstart generator or key transmission path identified in the system restoration plan becomes unavailable or unusable. Table 3.7-3 summarizes the responses. Fewer respondents identify expected actions than report having documented practices for awareness of blackstart capability. The difference in number of respondents might indicate that some documented practices pertain more to long-term capability than to current conditions.

In addition to the expected operator actions listed in Table 3.7-3, one RC respondent comments that the RC's outage coordinators "make sure that multiple adjacent black-start units are not planned out at the same time." Others who responded to this section of the survey did not specifically state that the RC makes a concerted effort to avoid compromising system restoration plans when reviewing and approving planned outages. Table 3.7-3 shows that there is a range of expected responses to a loss of blackstart capability, rather than a consistent, uniform set of responses.

Documented Actions for Inadequate Blackstart Capabilities	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	Others	Total
Notify management	X	X	X	X		X			X	X						13	**20**
Expedite current outages	X	X	X	X	X		X	X								8	**15**
Reschedule planned outages	X	X	X		X		X	X								9	**15**
Request engineering studies for additional options	X	X	X	X		X			X							14	**20**
Notify other entities (e.g., RCs, nuclear stations)	X	X	X		X	X										12	**17**

Table 3.7-3 — Documented Actions for Inadequate Blackstart Capability

Recommendations for New Reliability Standards

The *Outage Task Force Final Blackout Report* states that the NERC Reliability Standards are based on seven key concepts, one of which is emergency preparedness.[31] In the context of emergency preparedness, the report emphasizes the need for “procedures and capabilities to use ‘black start’ generators (capable of restarting with no external power source) and to coordinate operations in order to restore the system as quickly as possible to a normal and reliable condition."[32]

For the most part, the necessary “procedures and capabilities” are addressed in the EOP series of standards, in particular, NERC Reliability Standard EOP-005-0, System Restoration Plans. Although most of the requirements of this standard apply to long-term issues such as annual review and update of the plans, the standard contains a requirement (R8) that each TOP shall “ensure the availability and location of black-start capability within its area to meet the needs of the restoration plan.” Although this requirement does not specify the time frame to which it applies, an argument can be made that it must apply to the near-term or real-time situational awareness of the availability and capability of blackstart facilities.

Although NERC Reliability Standard EOP-005-0, System Restoration Plans, requires each TOP to “ensure the availability and location of black-start capability within its area to meet the needs of the restoration plan,” currently each TOP decides how to accomplish this goal.

Based on survey results, RTBPTF recommends that requirement R8 of NERC Standard-EOP-005-0 be revised to specify that operators receive the information they need to maintain situational awareness of the availability and capability of the blackstart generation and transmission resources identified in their system restoration plans. The task force also recommends that requirement R8 specify that operators be provided

[31] Outage Task Force Final Blackout Report, Pages 6–10.
[32] Ibid. Page 10.

documented practices and procedures that identify the information they should monitor to ensure adequate blackstart resources and the actions they should take if blackstart conditions are less than described in the restoration plan. The task force recommends that an operating guideline be developed to support the expanded requirement R8.

RTBPTF also recommends that NERC Standard-TOP-003-0, Planned Outage Coordination, be revised to include a requirement that scheduled outages of blackstart generation resources be coordinated so that key elements of the system restoration plan are not compromised without adequate alternative resources being available.

Recommendation – S35

Provide information to operators to maintain awareness of the availability and capability of the blackstart generators and transmission restoration paths.

RTBPTF Recommendation

RTBPTF recommends that requirement R8 of NERC Standard-EOP-005-0, System Restoration Plans, be revised to address operator awareness of the availability of blackstart resources, as follows:

PR1. Each transmission operator shall provide its operators with the information necessary to maintain awareness, in real time and on a current-day and day-ahead basis, of the availability and capability of the blackstart generation resources and transmission cranking paths identified in the system restoration plan. In addition, operators shall be provided documented practices and procedures that specify the information to be monitored to ascertain the availability and capability of blackstart resources and that identify the actions to be taken if blackstart availability or capability is less than that described in the restoration plan.

RTBPTF developed the following proposed measure (PM) for the proposed requirement above:

PM1. Each transmission operator shall demonstrate the documented practices and procedures that specify the information to be monitored to ascertain the availability and capability of blackstart resources and that identify the actions to be taken if blackstart availability or capability is less than that described in the restoration plan. In addition, each transmission operator shall demonstrate the user interface for visual presentation of the necessary information.

Recommendation – S36

Plan and coordinate scheduled outages of blackstart generators and transmission restoration paths.

RTBPTF also recommends that a requirement be added to Standard-TOP-003-0 to address scheduled outages of blackstart generation resources and/or key transmission restoration pathways.

PR2. Each reliability coordinator, transmission operator, balancing authority, and generator operator shall plan and coordinate scheduled outages of blackstart generation resources and/or key transmission restoration pathways so that the reliable capability of key elements of the system's restoration plans is not compromised without adequate redundant or alternative resources or plans being identified and available.

RTBPTF developed the following proposed measure for PR2:

PM2. Each reliability coordinator, transmission operator, balancing authority, and generator operator shall show evidence that the viability of the transmission owner's restoration plan is reaffirmed on a daily basis.

Rationale

The *Outage Task Force Final Blackout Report* reiterates the importance of having "procedures and capabilities" related to the blackstart resources needed to restore a transmission system following events such as the August 14, 2003, blackout. Reliability standards that address such procedures and capabilities currently focus on long-term issues such as verifying the capabilities of blackstart resources and updating blackstart procedures. The above recommendations will increase the scope and specificity of reliability standards to give operators the information and guidance they need to maintain situational awareness of the status, availability, and capability of blackstart resources and the viability of blackstart procedures in all time frames, up to and including real time. The findings of the Real-Time Tools Survey establish that documented procedures for maintaining situational awareness of blackstart capability are prevalent within the industry. The PRs and PMs presented above will establish formal, uniform requirements for documented and demonstrable procedures that will raise the bar for many reliability entities.

Recommendation – G12

Monitor and ensure operator awareness of current conditions of blackstart generators and status of transmission restoration paths.

Recommendations for Operating Guidelines

As discussed previously, every TOP is currently required to "ensure the availability and location of blackstart capability within its area to meet the needs of the restoration plan." Each TOP decides how to achieve this goal. Many survey respondents report that their system operators monitor a variety of information to maintain awareness of blackstart capability. Current practices provide a good guideline for others to follow in providing for the availability of blackstart resources.

RTBPTF recommends that an operating guideline be developed in support of requirement R8 of NERC Standard EOP-005-0, System Restoration Plans. The guideline should specify that system operators monitor the following information to maintain awareness of the current condition of blackstart resources:

- On-line/off-line status of blackstart generating units
- Scheduled return-to-service dates for outaged blackstart units
- Derated blackstart unit capacity
- Status of transmission lines along critical pathways for system restoration
- Scheduled return-to-service dates for outaged transmission lines along critical pathways for system restoration
- Status of transmission lines in alternative restoration pathways
- AVR status of blackstart units
- Fuel availability for blackstart units

The task force recommends that visualization techniques for efficiently and effectively providing system operators with information regarding blackstart capability, as listed in the operating guidelines recommended above, be developed by EMS vendors, EMS user groups, and the various forums available for the exchange of ideas among operators.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for blackstart capability.

Examples of Excellence

RTBPTF identified no examples of excellence related to blackstart capability.

Section 4.0
Power System Models

Introduction

An accurate real-time model is essential for assessing the reliability of the electric system. Real-time models that are too small, too large, too highly equivalenced, or inadequately maintained and updated can cause significant problems for entities that oversee reliability. A consistent, uniform set of modeling and data exchange practices, procedures, and standards will greatly facilitate the creation and subsequent maintenance of optimal models. The sections that follow summarize and analyze the model characteristics and modeling practices reported by respondents to the NERC Real-time Tools Survey. The analysis attempts to quantify some of the key characteristics of the respondents' network models and identifies modeling areas that need more analysis, from which recommendations for new reliability standards or guidelines may be forthcoming.

The fundamental responsibility of RCs, TOPs, and other entities that oversee grid reliability is to assure that the transmission system can be quickly restored to a secure state following any single contingency. The real-time tools that are necessary to assess the condition of the transmission system, such as the state estimator and contingency analysis, cannot function without a real-time model of the system. A real-time model is a high-fidelity representation of:

1) transmission and generation facilities within the area of responsibility of the reliability entity (the *internal network model*) and
2) facilities adjacent to and beyond the area of responsibility (the *external network model*) that can significantly impact voltage and flows within the area of responsibility or that provide a path for flows into or out of external facilities that can impact the area of responsibility.

Even the best-designed tools, no matter how advanced, can be severely compromised by inaccuracies and omissions in the network models on which they rely. Unfortunately, entities implementing network analysis applications for the first time often focus on the applications themselves and underestimate the cost, effort, and level of expertise required to build and maintain an adequate real-time network model.

Determining which facilities to represent in the internal network model is relatively straightforward. Typically, the internal model includes all bulk electric system facilities within the area of responsibility. Determining which facilities to represent in the external model is much more complex. There is no "bright line" that identifies external areas whose operations can impact the area of responsibility. Real-time modelers use a variety of criteria, analytical techniques, engineering judgment, and other methods to determine what to include and exclude in their external models. Although some variation in external models among regions is justified based upon the size and geographic location of a particular entity's area of responsibility, inconsistencies in identifying the relevant external facilities can lead to external models that are too small, too large, or too highly "equivalenced." In an equivalenced model, individual physical electrical elements are represented by a reduced set of non-physical elements that mimic the same electrical response as the individual elements. For example, multiple generating units may be represented by a single large generator that has the same total output, or a double-circuit line may be represented by a single-circuit line with the same effective impedance.

External models that are too small, too large, or too highly equivalenced each have characteristics that can negatively affect the quality of the results of the real-time network analysis tools that use them (and therefore the ability of reliability entities to do their jobs well).

External models that are too small may not include enough external transmission elements to accurately represent loop flows through external systems that can significantly impact internal facilities. In some cases, loop flows may not be represented at all or may be allocated in whole or in part to facilities in the external model over which they do not actually flow. A state estimator can often overcome this challenge in determining the actual flows and voltages on the internal facilities because it uses "best fit" algorithms (e.g., weighted least-squares methods) to estimate the current system state. However, contingency analysis cannot accurately calculate post-contingency flows on internal facilities if the branches that carry these flows are not accurately represented in nearby external facilities. The analysis may produce a solution that inaccurately suggests the system is secure when it is not, or the reverse. Similar problems can result when a model omits external facilities that would individually or collectively contribute to significant loading on internal facilities if those external facilities were out of service.

External models that are too large require more resources to maintain than they would otherwise. Reliability entities typically underestimate the resources required to build and maintain a real-time model and often do not have enough staff to keep up with both a detailed internal model and all the significant changes made to the external facilities included in a large, detailed external model. In addition, processes for notification of grid changes and exchange of relevant modeling data among reliability entities are minimal or even nonexistent in some regions. The result is that large, detailed models can gradually become inaccurate and obsolete over time. The state estimator may be able to overcome this challenge in determining the actual flows and voltages on internal facilities, but contingency analysis will not accurately calculate post-contingency flows and voltages on internal facilities if the representations of nearby external facilities are not correct. A large external model also causes network applications to use significant additional computer resources (memory, CPU cycles, discs, etc.), and these applications will take longer to solve. Consequently, the reliability entity may run state estimation, contingency analysis, and other network analysis applications less frequently.

External models that are highly equivalenced pose similar problems. A decision to represent a particular external facility as part of a fictitious “equivalent” element is usually based on a determination that the facility by itself does not have a significant impact on internal facilities but needs to be represented along with other similar facilities to provide a path for external flows into or out of facilities that are explicitly modeled. A problem occurs when a facility that has been incorporated into one or more equivalent elements has been upgraded in the field to the extent that it now needs to be modeled explicitly (e.g., from 115 kV to 230 kV). In most cases it is extremely difficult to deconstruct equivalenced elements into their constituent facilities for the purpose of remodeling one of them explicitly. The only sure way is to use equivalencing tools to recompute new external equivalent elements that are based on the new explicitly modeled facilities. This is a tedious, time-consuming task. For this reason, facility upgrades are often not incorporated into an equivalenced model. As above, the state estimator may be able to overcome this challenge in determining actual flows and voltages on the internal facilities, but contingency analysis will not be able to accurately reflect post-contingency flows on internal facilities if the representations of nearby external facilities are no longer correct.

Any external model that has not been sufficiently maintained can cause solution problems for the state estimator as well as contingency analysis and other applications that use the state estimator base case. The state estimator may have difficulty converging or fail to converge if the external model is outdated. In some cases, errors caused by poor external model fidelity can be “smeared” into internal facilities in the state estimator solution, causing inaccurate estimates for tie lines and other nearby internal facilities. Solution accuracy and convergence problems can impact contingency analysis similarly. When the state estimator fails to converge, real-time contingency analysis is effectively disabled. And even when the state estimator obtains a solution, a poor external model can cause contingency analysis to have convergence problems and/or yield erroneous solutions.

Good practice dictates that all relevant external electrical components, along with their associated real-time analog readings and circuit breaker and/or switch statuses, be modeled explicitly. Maintenance of accurate wide-area models requires continual exchange of system modeling data as well as exchange of real-time or near-real-time data with neighboring utilities. This exchange is required to support pertinent “instantaneous” metering and status information via SCADA/ICCP or other data links.

A consistent, uniform set of modeling and data-exchange practices, procedures, guidelines and/or standards facilitate the creation and subsequent maintenance of network models. RCs, TOPs, and all other entities responsible for reliability must have confidence that their neighbors are doing a competent job in assessing reliability and thereby protecting one another from harm. Real-time models are the foundation for these assessments. Therefore, all reliability entities have a vested interest in the quality and accuracy of their neighbors' real-time models.

RTBPTF recommends further analysis in the areas of model data exchange and grid change notification procedures, external model development guidelines, and the eventual use of CIM XML[1] for model exchange.

Significance to the August 14, 2003 Blackout

RTBPTF investigated the use of modeling data throughout the industry because the lack of real-time telemetry data in the external model was one of the contributing factors to the August 2003 blackout. MISO was using a static bus-branch network model in parts of its external model. When the Stewart-Atlanta 345-kV line tripped (monitored by the PJM RC), MISO's state estimator did not know that the line had gone out of service. This led to a data mismatch that prevented MISO's state estimator from computing a solution that could be used by its real-time contingency analysis application. Without real-time contingency analysis, MISO's ability to see that its system was in danger was greatly compromised.

Recommendations for New Reliability Standards

The Real-Time Tools Survey reveals that entities have significantly different practices for creating and maintaining models of the bulk electric system. Therefore, RTBPTF did not make any recommendations for the creation of new reliability standards pertaining to model practices. However, RTBPTF does identify several areas that require additional analysis to improve the state of modeling within the industry. The items that will require additional analysis include providing clarity to some fundamental definitions, identifying methods for grid change notification and model data exchange, developing external models, and implementing a CIM XML model exchange.

[1] The term "CIM XML" in this report refers to the language used for power system model exchange that conforms to the NERC common power system model (CPSM) specifications. "CIM" is the "Common Information Model" definition used to represent the power system. XML (extensible mark-up language") is an industry standard syntax used in the model data files.

Section 4.1
Model Characteristics

Definition

The majority of real-time applications used to monitor and study the health of the transmission grid require an electrical model of the interconnection, which is commonly referred to as the "network model." The network model has two components: the "internal model" and the "external model." The internal model represents the portion of the transmission grid for which the reliability entity is responsible (i.e., the electrical footprint of an RC or TOP). The external model represents the electric grid that surrounds an entity's primary area of responsibility.

Background

In general, the internal network model contains significantly more detail than the external model in terms of both voltage levels and the types of equipment represented. The external model also often contains "equivalent" elements. An equivalent element is a fictitious (non-physical) element that represents two or more physical elements (e.g., a single "generator" that represents multiple generators, a single "line" that represents multiple lines, etc.). Equivalent elements provide the same electrical response as the elements they replace in the model. They are generally employed on the outer edges and/or within lower-voltage levels of the model where physical representation is not critical.

Summary of Findings

The questions in the model characteristics section of the NERC Real-time Tools Survey were designed to capture essential characteristics of the respondents' internal and external network models. The information collected in this section of the survey also provides insight into the respondents' network modeling practices.

The data collected in this section of the survey are primarily related to the respondents' network model dimensions and modeling practices. This information is intended to provide context and support for information collected in other sections of the survey. The analysis of findings below is organized into the following modeling categories:

- general model size and detail
- future modeling plans
- applications that use the network model
- circuit breaker and switch modeling
- generator step-up transformer modeling

- generator auxiliary load modeling
- generating unit Mvar capability curve modeling
- verifying transmission-line characteristics
- transmission line real-time limits
- transformer real-time limits
- bus load modeling
- external network models

Some of the key survey findings are listed below:

- Survey respondents' network models vary widely in terms of size, as one would expect. However they also vary widely in modeling detail (in terms of switches and elementary bus nodes per station); internal-to-total bus ratios, internal-to-total branch ratios; analog and status measurement density; and other dimensions that are normalized by buses, stations, and other basic model dimensions. This wide variation was seen in responses from both RCs and non-RCs.

- A large number of respondents plan major changes in their network models that are "above and beyond routine model changes" in the coming year, particularly in their external models.

- An overwhelming majority of respondents consider the state estimator, real-time contingency analysis, study contingency analysis, and on-line power flow to be the most important applications that rely on the network model. Other network applications such as operator OPF, Volt-var dispatch, etc. were cited to a much lesser extent.

- Higher-voltage portions of respondents' power systems are modeled in more detail (in terms of power breakers and switches) than the lower-voltage portions of their systems. Also, circuit breaker devices are modeled more than switches (i.e., gangs, disconnects, etc.)

- An overwhelming majority of respondents model at least some generator step-up transformers, generator auxiliary loads, and generating unit Mvar capability curves in their internal network models. This is typically done for the larger generating units. Surprisingly, not all RCs model generating unit Mvar capability curves despite the importance of these curves for determining Mvar reserves.

- Half or fewer of survey respondents verify the electrical characteristics of their transmission lines.

- More than 75 percent of all survey respondents, including 90 percent of RCs, report that their network models support the use of real-time limits and/or multiple limit sets based on temperatures or seasons for lines and transformers. Of those respondents whose models support this feature, almost 90 percent are using it for lines, and about 75 percent are using it for transformers.

- The majority of respondents use multiple methods to determine the elements to include in their external models (e.g., off-line modeling utilities, system planning studies, etc.). Surprisingly, more than one-third of the RCs use "engineering judgment" as the sole means of determining what elements to include in their external models.

- CIM XML[2] is not currently used to a wide extent for model maintenance.

- Virtually all of the respondents have at least some real-time analog and/or status telemetry linked to their external network models. However the real-time analog/status point measurement density in the external models, in terms of measurements per station, varies widely. (Note: The lack of real-time telemetry data in the external model was one of the contributing factors in the August 2003 blackout).

The information in the subsections below is based upon an analysis of the data submitted by survey respondents. Note that because of the length of the survey and the volume of data involved, RTBPTF was not able to filter all of the responses for inconsistencies, omissions, and suspect data entries, or to follow up with each of the respondents.

General Model Size and Detail

The survey collected information on the size and detail of each respondent's network model. The data collected included basic network model dimensions such as numbers of buses, lines, breakers, switches, transformers, and other system elements. Network model size is commonly expressed in terms of buses and branches.[3] Table 4.1-1 and Table 4.1-2 show the numbers of model buses and branches reported by survey respondents.[4]

From Table 4.1-1 we see that the network models used by RCs vary widely in size from 687 buses to more than 30,000 buses. From Table 4.1-2 we see that the models used by all other respondents (e.g., TOPs and BAs) also vary widely

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[2] The term "CIM XML" in this report refers to the language used for power system model exchange that conforms to the NERC common power system model (CPSM) specifications. "CIM" is the "Common Information Model" definition used to represent the power system. XML (extensible mark-up language") is an industry standard syntax used in the model data files.
[3] A "branch" in this context includes lines (real or equivalent), transformers (of any type), "zero impedance" branches, and series capacitors/reactors.
[4] The identities of the respondents in this and other sections of this report have been masked. The identifiers used for each respondent change in each table and figure. That is, respondent "RC01" in one figure or table is not necessarily the same respondent as "RC01" in a different figure or table.

in size from 14 buses to more than 24,000 buses. The charts in Figure 4.1-1 and Figure 4.1-2 graphically illustrate this. Both RCs and the other respondents exhibit similar wide variations in the number of model branches.

The size of each survey respondent's external model relative to the total model size also varies widely. This variation is clearly illustrated by the differences in the respondents' external bus to total bus ratios, as can be seen in Table 4.1-1 and Table 4.1-2 (see also Figure 4.1-3 and Figure 4.1-4). A similar variation is also seen in the external-branch-to-total-branch ratios. RCs report external-bus-to-total-bus model ratios that ranged from less than one percent to almost 81 percent while all other respondents report ratios that varied between seven and 67 percent. Similarly, RCs report external-branch-to-total-branch ratios that range from less than one percent to 82 percent. The other respondents had external-branch-to-total-branch ratios that range from less than one percent to 94 percent.

Some of the wide variation in external model sizes can be explained by a respondent's geographic location within an interconnection. For instance, a system in Florida with interconnection ties only to the north would likely require a smaller external model than a system in Ohio with ties to the interconnection on all sides. However, much of this variation is also due to the diversity of modeling approaches and philosophies used to determine how large an external model is required to support network applications. This topic is addressed in greater detail in Section 4.2, Modeling Practices and Tools, of this report.

Resp[5]	Internal Buses	External Buses	Total Buses	Internal Branches	External Branches	Total Branches	External Bus to Total Bus Ratio	External Branch to Total Branch Ratio
RC01	12,834	17,873	30,707	17,348	24,516	41,864	0.58	0.59
RC02	7,624	4,837	12,461	9,891	8,548	18,439	0.39	0.46
RC03	4,330	6,239	10,569	5,673	9,633	15,305	0.59	0.63
RC04	3,750	3,420	7,170	4,643	6,654	11,297	0.48	0.59
RC05	1,334	5,580	6,914	1,610	7,146	8,756	0.81	0.82
RC06			5431			3,862		
RC07	5,157	9	5,166	6,455	7	6,462	0.002	0.001
RC08	2,166	1,577	4,564	3,485	4,025	7,510	0.35	0.54
RC09	2,507	1,575	4,082	1,751	5,479	7,230	0.39	0.76
RC10	3,251	638	3,889	3,891	1,165	5,056	0.16	0.23
RC11			3,674			4,935		
RC12	3,300	300	3,600	2,206	182	2,388	0.08	0.08
RC13	1,923	1,506	3,429	2,380	2,216	4,596	0.44	0.48
RC14	1,770	463	2,233	2,561	630	3,191	0.21	0.20
RC15	1,287	445	1,732	1,822	776	2,598	0.26	0.30
RC16	1,110	60	1,270	1,053	41	1,094	0.05	0.04
RC17	672	15	687	767	19	786	0.02	0.02
Count	15	15	17	15	15	17	15	15
Average	3,534	2,969	6,328	4,369	4,736	8,551	0.32	0.38
Median	2,507	1,506	4,082	2,561	2,216	5,056	0.35	0.46
Std Dev	3,154	4,633	7,006	4,334	6,433	9,839	0.24	0.28
Max	12,834	17,873	30,707	17,348	24,516	41,864	0.81	0.82
Min	672	9	687	767	7	786	0.002	0.001

Table 4.1-1 — Bus and Branch Count for RC Respondents[6]

[5] Aliases are used to mask RCs' names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, "RC 01" in any given table is not the same as "RC 1" or the equivalent identifier in another table in this report.
[6] Some computed quantities are blank for entities that did not provide an internal/external breakdown of their buses and branches.

Resp	Internal Buses	External Buses	Total Buses	Internal Branches	External Branches	Total Branches	External to Total Bus Ratio	External to Total Branch Ratio
R01	8,087	16,138	24,225	8,389	22,783	31,173	0.67	0.73
R02	7,014	1,073	8,087	7,120	1,269	8,389	0.13	0.15
R03	900	7,100	8,000	681	10,674	11,355	0.89	0.94
R04	2,751	2,190	4,941	3,470	2,567	5,082	0.44	0.51
R05	1,589	2,505	4,094	1,770	4,628	6,398	0.61	0.72
R06	600	3,090	3,690	857	5,492	6,349	0.84	0.87
R07	973	1,952	2,925	1,190	3,509	4,699	0.67	0.75
R08	761	2,135	2,896	887	3,252	4,139	0.74	0.79
R09	1,838	504	2,342	2,215	544	2,759	0.22	0.20
R10	382	1,906	2,288	504	3,428	3,932	0.83	0.87
R11	468	1,722	2,190	550	2,912	3,462	0.79	0.84
R12	1,482	657	2,139	1,799	1,032	2,831	0.31	0.36
R13	630	1,150	1,780			2,889	0.65	
R14	282	1,298	1,580	593	3,066	3,659	0.82	0.84
R15	581	929	1,510			1,979	0.62	
R16	1,070	167	1,237	2,038	428	2,466	0.14	0.17
R17	1,058	10	1,058	1,389	7	1,396	0.01	0.01
R18	170	630	800	651	2,109	2,760	0.79	0.76
R19	180	420	600	125	546	671	0.70	0.81
R20	450	40	490	570	20	590	0.08	0.03
R21	208	2	210	296	2	298	0.01	0.01
R22	50	10	60	159	10	169	0.17	0.06
R23	13	1	14	22	4	26	0.07	0.15
Count	23	23	23	21	21	23	23	21
Average	1,371	1,984	3,355	1,680	3,252	4,673	0.49	0.50
Median	630	1,073	2,139	857	2,109	2,889	0.62	0.72
Std Dev	2,061	3,452	5,050	2,195	5,146	6,398	0.31	0.35
Max	8,087	16,138	24,225	8,389	22,783	31,173	0.89	0.94
Min	13	1	14	22	2	26	0.009	0.005

Table 4.1-2 — Model Bus and Branch Count for Other (non-RC) Respondents[7]

[7] Some computed quantities are blank for entities that did not provide an internal/external breakdown of their buses and branches.

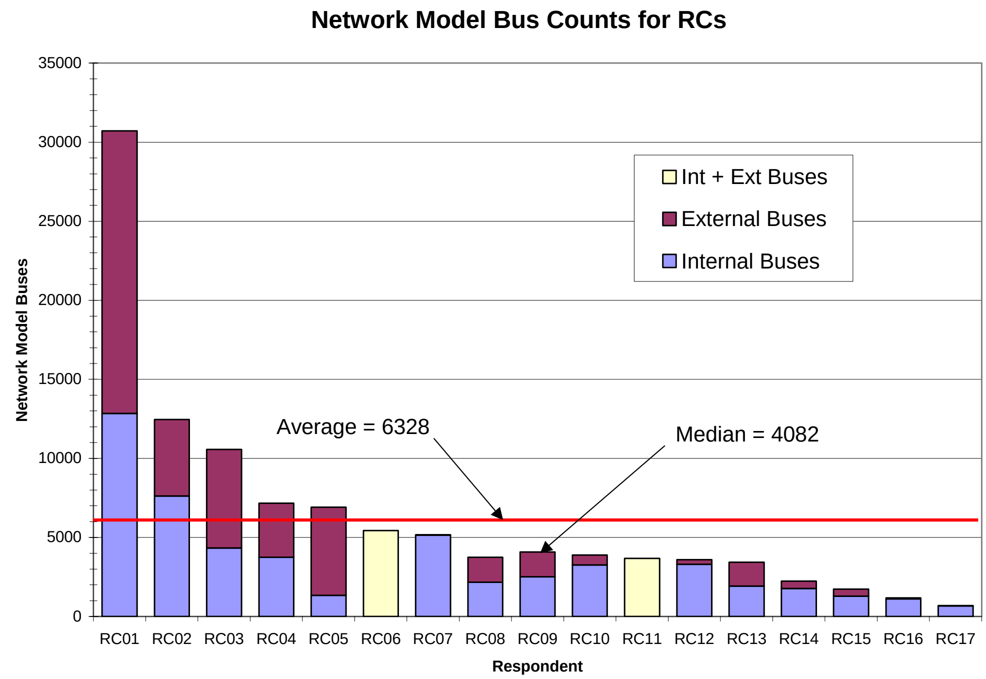

Figure 4.1-1

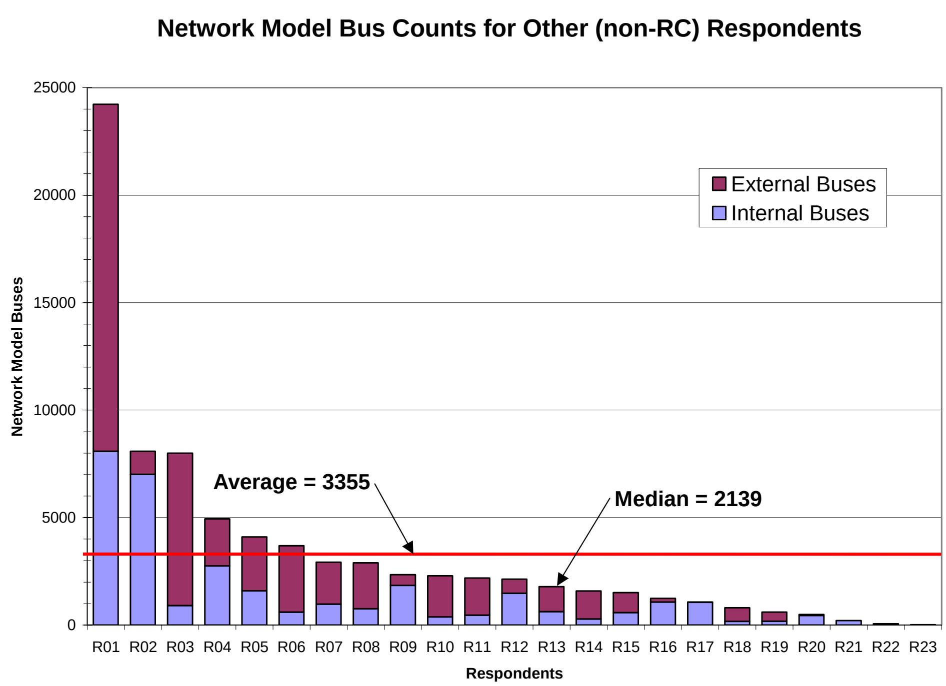

Figure 4.1-2

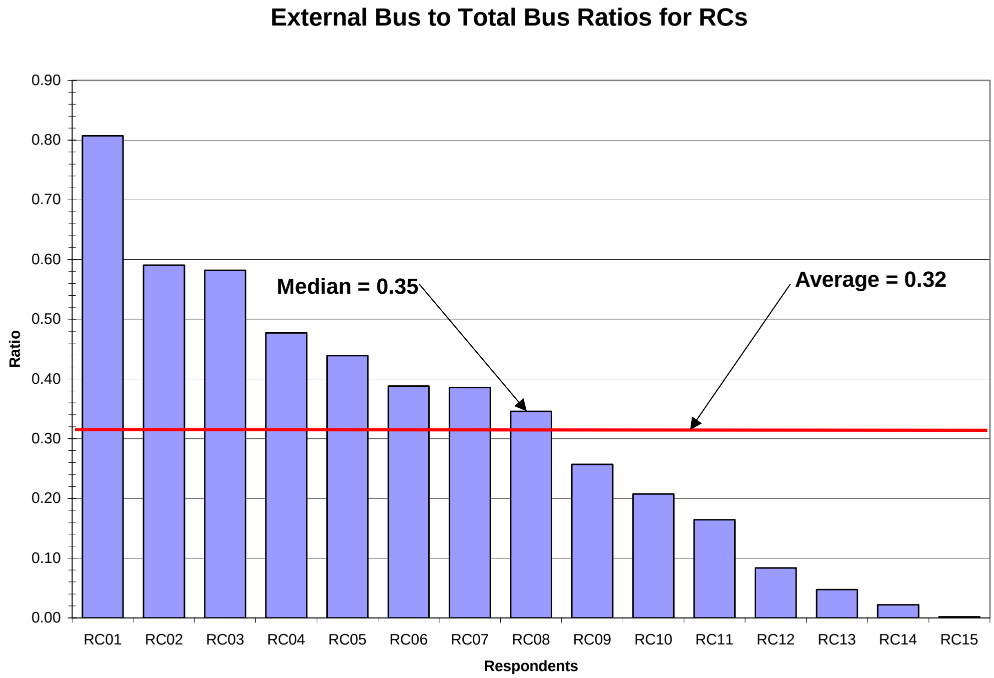

Figure 4.1-3

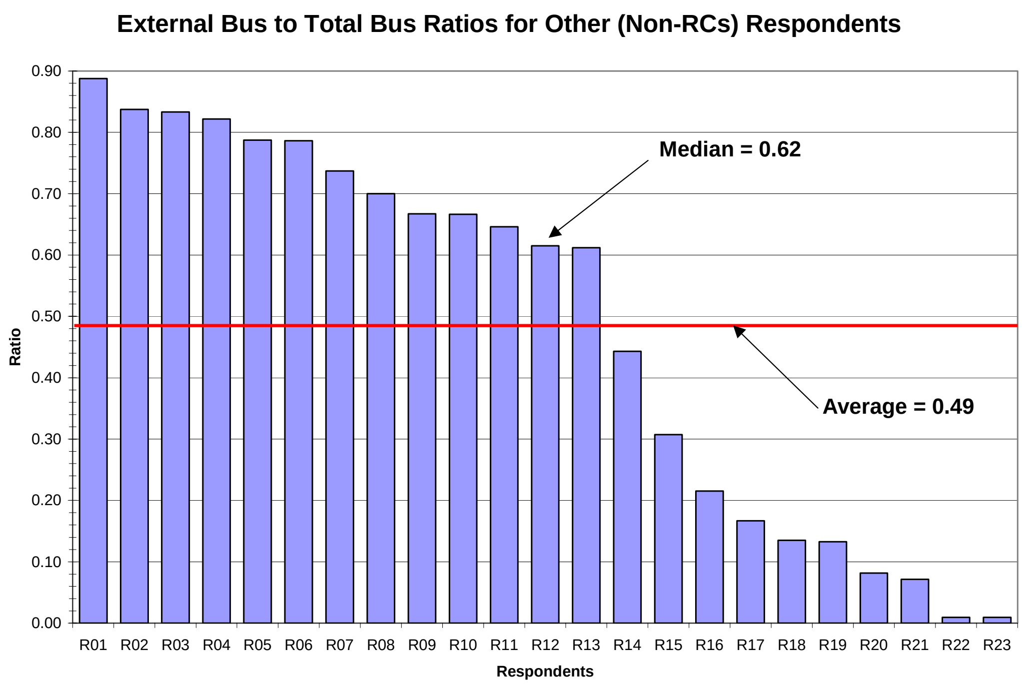

Figure 4.1-4

Approximate measures for quantifying model detail were computed to compare the level of detail in respondents' models. The two measures that were used were:

- Breakers and switches per station ratio
- Elementary bus nodes per electrical bus ratio

These are very rough measures that are affected by many transmission system specific characteristics. However they provide a good approximation of modeling detail in most cases. In general, a more detailed model (in terms of equipment and voltage levels modeled) will contain larger numbers of breakers and switches per station than one with less detail. The same is true for the node-to-bus ratio because modeling additional equipment generally requires that the model use more nodes. In the extreme case of a planning model (i.e., a bus-branch model), the breakers and switches per station ratio for is zero. The node-to-bus ratio for a planning model is one.

Table 4.1-3 and Table 4.1-4 show the number of stations, breaker-and-switch totals, and the breakers-and-switches-to-station ratios for the RCs and other respondents. Table 4.1-5 and Table 4.1-6 show the number of buses, elementary bus nodes, and the elementary-bus-nodes-per-bus ratios for the RCs and other respondents. In each of these tables, the raw data and computed ratios are shown for the internal model, the external model, and total model.

From Table 4.1-3 and Table 4.1-4, we see that the breakers-and-switches-per-station ratios vary widely among respondents. This is true for both the RCs and other respondents. We also see that the computed ratio is larger for the internal model than it is for the external model for most respondents. In many of the cases where the external ratio is large, it seems to be because the external model is very small relative to the total model. The average and median ratios for the internal models are significantly larger than those for the external models, as one might expect.

From Table 4.1-5 and Table 4.1-6, we see that the elementary-bus-node-to-electrical-bus-node ratios also vary widely among respondents. The computed values of the node-to-bus ratios vary the same way that the breakers-and switches-per-station ratio varies. That is, there is wide variation for both the RCs and other respondents. Also, the ratio for the internal model is larger than it is for the external model in most cases. As with the breaker-and-switch-per-station ratios, the average and median node-to-bus ratios for the internal models are significantly larger than those for the external models.

One can conclude these ratios are generally larger for the internal models because they contain more breaker/switch detail than the external models. This is consistent with what one would expect. The large variation among respondents in the ratios can be explained, in part, by a number of factors related to the physical characteristics of the systems being modeled (e.g., the bus and breaker schemes used on the bulk electric system, etc.). However, another likely reason for this variation is differences in the respondents' modeling philosophies and practices. This will be illustrated later by some of the other survey responses that will be discussed.

Resp	Internal Stations	External Stations	Total Stations	Internal Breakers + Switches	External Breakers + Switches	Total Breakers + Switches	Int Breakers + Switches to Int Station Ratio	Ext Breakers + Switches to Ext Station Ratio	Total Breakers + Switches to Total Station Ratio
RC01	1,566	383	1,949	42,897	3,262	46,159	27.39	8.52	23.68
RC02	233	21	254	4,503	102	4,600	19.33	4.86	18.11
RC03	-----	-----	1,634	-----	-----	21,126	-----	-----	12.93
RC04	1,676	18	1,694	-----	-----	21,635	-----	-----	12.77
RC05	296	6	302	2,785	55	2,840	9.41	9.17	9.40
RC06	3,589	9	3,598	33,412	29	33,441	9.31	3.22	9.29
RC07	3,675	3,314	6,989	38,406	26,082	64,488	10.45	7.87	9.23
RC08	1,425	344	1,769	12,954	3,207	16,161	9.09	9.32	9.14
RC09	999	168	1,169	9,215	1,256	10,471	9.22	7.48	8.96
RC10	770	211	981	6,431	1,915	8,310	8.35	9.08	8.47
RC11	623	3,066	3,689	11,557	18,980	30,537	18.55	6.19	8.28
RC12	8,737	1,389	20,126	69,079	68,283	137,362	7.91	6.00	6.83
RC13	967	1,229	2,196	5,460	7,831	13,291	5.65	6.37	6.05
RC14	2,122	1,982	4,104	22,284	2,183	24,467	10.50	1.10	5.96
RC15	1,435	1,201	2,636	10,218	1,636	11,854	7.12	1.36	4.50
RC16	3,644	4,828	8,472	17,585	13,714	31,299	4.83	2.84	3.69
RC17	1,791	1,094	3,591	10,292	2,865	9,157	5.75	2.62	2.55
Count	16	16	17	15	15	17	15	15	17
Average	2,097	1,829	3,833	19,805	10,093	28,659	10.86	5.73	9.40
Median	1,501	739	2,196	11,557	2,865	21,126	9.22	6.19	8.96
Std Dev	2,094	2,925	4,737	18,558	17,861	32,219	6.17	2.90	5.24
Max	8,737	11,389	20,126	69,079	68,283	137,362	27.39	9.32	23.68
Min	233	6	254	2,785	29	2,840	4.83	1.10	2.55

Table 4.1-3 — Breakers and Switches per Station for RC Respondents

Resp	Internal Stations	External Stations	Total Stations	Internal Breakers + Switches	External Breakers + Switches	Total Breakers + Switches	Int Breakers + Switches to Int Station Ratio	Ext Breakers + Switches to Ext Station Ratio	Total Breakers + Switches to Total Station Ratio
R01	500	1,000	1,500	-----	-----	-----	-----	-----	-----
R02	-----	-----	-----	417	11	428	-----	-----	-----
R03	60	80	140	2,400	1,000	3,400	40.00	12.50	24.29
R04	120	2	122	-----	-----	1,433	-----	-----	11.75
R05	836	48	884	8,298	235	8,533	9.93	4.90	9.65
R06	1,756	1,471	3,227	12,833	12,149	29,829	7.31	8.26	9.24
R07	350	8	358	3,000	30	3,030	8.57	3.75	8.46
R08	580	4	584	4,700	170	4,870	8.10	42.50	8.34
R09	2,746	768	3,516	19,371	4,742	29,181	7.05	6.17	8.30
R10	100	280	380	1,160	1,200	2,360	11.60	4.29	6.21
R11	3,514	10,928	14,442	24,113	63,596	87,709	6.86	5.82	6.07
R12	800	301	1,101	6,407	57	6,464	8.01	0.19	5.87
R13	299	1,911	2,210	2,345	9,622	11,967	7.84	5.04	5.41
R14	50	10	60	275	15	290	5.50	1.50	4.83
R15	13	1	14	65	2	67	5.00	2.00	4.79
R16	282	1,298	1,580	1,416	5,484	6,900	5.02	4.22	4.37
R17	-----	-----	1,240	-----	-----	5,000	-----	-----	4.03
R18	578	1,718	2,296	5,633	1,566	7,199	9.75	0.91	3.14
R19	667	1,138	1,805	4,628	476	5,104	6.94	0.42	2.83
R20	600	3,090	3,690	4,600	1,600	6,200	7.67	0.52	1.68
R21	303	1,084	1,387	1,667	517	2,184	5.50	0.48	1.57
R22	437	5,556	5,993	2,292	2,809	5,101	5.24	0.51	0.85
R23	620	1,670	2,290	1,336	544	1,880	2.15	0.33	0.82
Count	21	21	22	20	20	22	19	19	21
Average	724	1,541	2,219	5,348	5,291	10,415	8.84	5.49	6.31
Median	500	1,000	1,444	2,700	772	5,051	7.31	3.75	5.41
Std Dev	895	2,524	3,102	6,446	14,130	19,000	7.84	9.54	5.13
Max	3,514	10,928	14,442	24,113	63,596	87,709	40.00	42.50	24.29
Min	13	1	14	65	2	67	2.15	0.19	0.82

Table 4.1-4 — Breakers and Switches per Station for Other (non-RC) Respondents

Resp	Internal Buses	External Buses	Total Buses	Internal Nodes	External Nodes	Total Nodes	Internal Node to Internal Bus Ratio	External Node to External Bus Ratio	Total Node to Bus Ratio
RC01	1,770	463	2,233	30,554	6,200	36,754	17.26	13.39	16.46
RC02	3,251	638	3,889	42,374	3,397	45,771	13.03	5.32	11.77
RC03	5,157	9	5,166	50,000	100	50,100	9.70	11.11	9.70
RC04	-----	-----	3,674	-----	-----	22,567	-----	-----	6.14
RC05	2,166	1,577	4,564	14,593	8,896	27,929	6.74	5.64	6.12
RC06	1,287	445	1,732	8,064	2,373	10,437	6.27	5.33	6.03
RC07	7,624	4,837	12,461	-----	-----	74,336	-----	-----	5.97
RC08	672	15	687	3,593	40	3,633	5.35	2.67	5.29
RC09	12,834	17,873	30,707	76,809	80,430	157,239	5.98	4.50	5.12
RC10	1,334	5,580	6,914	11,398	22,177	33,575	8.54	3.97	4.86
RC11	1,923	1,506	3,429	10,819	2,866	13,685	5.63	1.90	3.99
RC12	3,750	3,420	7,170	22,753	5,574	28,327	6.07	1.63	3.95
RC13	4,330	6,239	10,569	20,609	20,071	40,680	4.76	3.22	3.85
RC14	1,110	60	1,270	4,628	130	4,758	4.17	2.17	3.75
RC15	-----	-----	5,431	-----	-----	16,846	-----	-----	3.10
RC16	3,300	300	3,600	8,259	608	8,867	2.50	2.03	2.46
RC17	2,507	1,575	4,082	-----	-----	4,082	-----	-----	1.00
Count	15	15	17	13	13	17	13	13	17
Average	3,534	2,969	6,328	23,419	11,759	34,093	7.38	4.84	5.86
Median	2,507	1,506	4,082	14,593	3,397	27,929	6.07	3.97	5.12
Std Dev	3,154	4,633	7,006	21,542	21,872	37,107	3.98	3.60	3.73
Max	12,834	17,873	30,707	76,809	80,430	157,239	17.26	13.39	16.46
Min	672	9	687	3,593	40	3,633	2.50	1.63	1.00

Table 4.1-5 — Elementary Node-to-Bus Ratios for RC

Resp	Internal Buses	External Buses	Total Buses	Internal Nodes	External Nodes	Total Nodes	Internal Node to Internal Bus Ratio	External Node to External Bus Ratio	Total Node to Bus Ratio
R01	2,751	2,190	4,941	-----	-----	-----	-----	-----	-----
R02	1,482	657	2,139	-----	-----	-----	-----	-----	-----
R03	1,070	167	1,237	8,911	1,329	10,240	8.33	7.96	8.28
R04	170	630	800	1,000	5,000	6,000	5.88	7.94	7.50
R05	180	420	600	1,300	2,500	3,800	7.22	5.95	6.33
R06	973	1,952	2,925	5,816	12,624	18,440	5.98	6.47	6.30
R07	450	40	490	3,000	50	3,050	6.67	1.25	6.22
R08	382	1,906	2,288	2,000	12,227	14,227	5.24	6.42	6.22
R09	208	2	210	1,275	14	1,289	6.13	7.00	6.14
R10	468	1,722	2,190	2,028	10,998	13,026	4.33	6.39	5.95
R11	1,058	10	1,058	5,728	131	5,859	5.41	13.10	5.54
R12	630	1,150	1,780	5,000	3,000	8,000	7.94	2.61	4.49
R13	8,087	16,138	24,225	29,886	76,854	106,740	3.70	4.76	4.41
R14	581	929	1,510	-----	-----	6,638	-----	-----	4.40
R15	7,014	1,073	8,087	24,711	5,175	29,886	3.52	4.82	3.70
R16	1,838	504	2,342	7,447	572	8,019	4.05	1.13	3.42
R17	50	10	60	450	50	200	9.00	5.00	3.33
R18	1,589	2,505	4,094	6,921	3,768	10,689	4.36	1.50	2.61
R19	900	7,100	8,000	2,677	10,177	12,854	2.97	1.43	1.61
R20	761	2,135	2,896	2,001	2,641	4,642	2.63	1.24	1.60
R21	600	3,090	3,690	600	3,090	3,690	1.00	1.00	1.00
R22	282	1,298	1,580	282	1,298	1,580	1.00	1.00	1.00
R23	13	1	14	13	1	14	1.00	1.00	1.00
Count	23	23	23	20	20	21	20	20	21
Average	1,371	1,984	3,355	5,552	7,575	12,804	4.82	4.40	4.34
Median	630	1,073	2,139	2,353	2,821	6,638	4.80	4.79	4.41
Std Dev	2,061	3,452	5,050	7,930	16,849	22,634	2.40	3.31	2.25
Max	8,087	16,138	24,225	29,886	76,854	106,740	9.00	13.10	8.28
Min	13	1	14	13	1	14	1.00	1.00	1.00

Table 4.1-6 — Elementary Node-to-Bus Ratios for Other (non-RC) Respondents

Future Modeling Plans

The models used by network applications require continual maintenance to reflect changes that occur in the interconnection that are both internal and external to an entity's reliability footprint. Survey respondents were asked to identify the "major" modeling activities that they were planning in the upcoming year that were "above and beyond of what is considered routine maintenance." Approximately 88 percent (15 of 17) of the RCs and 75 percent (18 out of 24) of other respondents plan make major changes to their network models within the coming year. Table 4.1-7 summarizes these responses.

Major Model Changes in Coming Year	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Adding breaker/switch detail to external model	X	X	X	X			X	X	X							NR	NR	7	**14**
Adding breaker/switch detail to internal model	X	X	X	X	X											NR	NR	7	**12**
Adding extensive telemetry to external model	X	X	X			X	X	X	X							NR	NR	6	**13**
Adding extensive telemetry to internal model	X	X		X	X	X							X			NR	NR	3	**9**
Adding lower-voltage detail to external model	X									X						NR	NR	3	**5**
Adding lower-voltage level detail to internal model	X	X	X	X												NR	NR	4	**8**
Adding one or more control areas to external model	X					X										NR	NR	3	**5**
Creating a new external model	X									X	X	X			X	NR	NR	10	**15**
Others			X		X						X			X		NR	NR	5	**9**

Table 4.1-7 — Major Model Changes Planned in the Upcoming Year

The most common changes planned by the 15 RC respondents are “adding breaker/switch detail to the external model” (47 percent, 7 out of 15), and “adding extensive telemetry to the external model” (47 percent, 7 out of 15). These are closely followed by “adding extensive telemetry to the internal model” (40 percent, 6 out of 15), “adding breaker/switch detail to the internal model” (33 percent, 5 out of 15), and “creating a new external model” (33 percent, 5 out of 15). Therefore, from the table we can see that 75 percent (12 out of 15) of RC respondents are making one or more major changes to their external models in the coming year.

The most common model changes planned by the other non-reliability coordinator respondents are “creating a new external model” (56 percent, 10 out of 18), “adding breaker/switch detail to the external model” (39 percent, 7 out of 18), “adding extensive telemetry to the external model” (33 percent, 6 out of 18), and “adding breaker/switch detail to the internal model” (39 percent, 7 out of 18).

The observations above suggest that most major network model changes that the survey respondents will be implementing in the near term are related to external network model improvements. These types of changes enhance the wide-area analysis capabilities provided by the various EMS network analysis applications that were recommended by Macedo (2004).[8]

[8] Macedo, Frank. Consultant to FERC. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

Applications that use the Network Model

A total of 41 entities, including 100 percent (17 out of 17) of the RCs, responded to the survey question that identified the applications that use their network models. Table 4.1-8 lists the on-line and off-line applications that use the survey respondents' network models.

Applications that Use the Network Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
State estimator	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	19	**36**
Real-time contingency analysis	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	19	**36**
Study contingency analysis	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	19	**36**
On-line power flow	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		19	**35**
Operator optimal power flow (OPF)		X	X	X		X	X						X	X				6	**13**
Other(s)	X	X	X		X							X						6	**11**
Equipment outage scheduler	X	X	X	X	X				X	X								3	**10**
Volt/Var dispatch (OPF)	X			X			X											5	**8**
Available Transfer Capability and Total Transfer Capability (ATC/TTC) applications	X	X				X		X			X							2	**7**
Market systems	X	X			X	X		X	X	X									**7**
Fault locator			X															2	**3**

Table 4.1-8 — Applications that Use the Network Model

From Table 4.1-8 we see that 100 percent (17 out of 17) of the RCs and 79 percent (19 out of 24) of the other respondents reported that their network models are used by their state estimator, real-time contingency analysis, and study contingency analysis applications. Ninety-four percent (16 of 17) of RCs and 79 percent (19 out of 24) of the other respondents report that their network models are used by their on-line power flow application. One can conclude that these four applications are clearly the ones that all of the survey respondents, regardless of their role, perceive as most important to their operations.

The respondents use their network models in other applications to a lesser extent. From Table 4.1-8 we see that 41 percent (7 out of 17) of the RCs and 25 percent (6 of 24) of the other respondents use their network models in an OPF application. Forty-one percent (7 out of 17) of RCs and 13 percent (3 out of 24) of other respondents use their network models in equipment-outage scheduling applications. Eighteen percent (3 out of 17) of RCs and 21 percent (5 out of 24) of other respondents use their models in Volt/Var dispatch applications (which are generally OPF applications). Twenty-nine percent (5 out of 17) of RCs and 8 percent of the other respondents use their network models in available transfer capability (ATC)/total transfer capability (TTC) applications. Forty-one percent (7 out of 17) of RC respondents and none of the other respondents use their network models in market-related applications. The network models are used by other applications to a lesser extent because:

- Some of the applications listed are only needed by entities that have markets or other special needs.

- Applications such as OPF are much more difficult to implement and maintain than the state estimator, contingency analysis, and on-line power flow. Consequently, they are generally not implemented unless there is a pressing need for them that justifies the cost.

Breaker/Switch Modeling

The survey reveals that, in their internal models, respondents represent a higher percentage of their existing circuit breakers at high-voltage levels than at lower-voltage levels. This is what one would intuitively expect. Table 4.1-9 and Table 4.1-10 summarize the actual survey responses for all RC respondents and non-RC respondents, respectively, regarding this issue.[9]

Voltage Range	N/A	<5 percent	5-25 percent	26-50 percent	51-75 percent	76-95 percent	>95 percent	**Total**
Voltage: 345 - 765 kV	1		1			1	12	**15**
Voltage: 100 - 230 kV	1				2	4	8	**15**
Voltage: < 100 kV	3		3	1		4	4	**15**

Table 4.1-9 — Percentage of Internal System Breakers Modeled for RCs

Voltage Range	N/A	<5 percent	5-25 percent	26-50 percent	51-75 percent	76-95 percent	>95 percent	**Total**
Voltage: 345 - 765 kV	6	2	2				14	**24**
Voltage: 100 - 230 kV	4		1	1	2	4	14	**26**
Voltage: < 100 kV	5		2	3	4	2	9	**25**

Table 4.1-10 — Percentage of Internal System Breakers Modeled for Other (non-RC) Respondents

The survey results also indicate that the higher-voltage portions of the internal system models contain more detail regarding circuit breakers than do the lower-voltage portions. For example, more than 85 percent (12 out of 14, excluding "N/A" responses) of survey respondents state that more than 95 percent of their circuit breakers were modeled for the portions of their internal system models for 345 kV and higher; less than 40 percent (4 out of 14, excluding "N/A" responses) state that 95 percent of their breakers were modeled below the 100-kV level.

Table 4.1-11 and Table 4.1-12 summarize the survey results for modeling internal system switches (i.e., disconnects, gangs, etc.) for RC and other respondents respectively.

[9] The number of respondents varied depending on voltage range. This is probably because some respondents did not select "N/A" for voltage ranges they do not have in their systems.

Voltage Range	N/A	<5 percent	5-25 percent	26-50 percent	51-75 percent	76-95 percent	>95 percent	Total
Voltage: 345 - 765 kV	1		1	2	1	2	8	**15**
Voltage: 100 - 230 kV	1		1	3	2	2	6	**15**
Voltage: < 100 kV	3	1	2	2	1	4	2	**15**

Table 4.1-11 — Percentage of Internal System Switches Modeled for RC Respondents

Voltage Range	N/A	<5 percent	5-25 percent	26-50 percent	51-75 percent	76-95 percent	>95 percent	Total
Voltage: 345 - 765 kV	6	2	-	1	1	1	11	**22**
Voltage: 100 - 230 kV	4		2	3	1	3	11	**24**
Voltage: < 100 kV	5	1	3	1	6	1	7	**24**

Table 4.1-12 — Percentage of Internal System Switches Modeled for Other (non-RC) Respondents

The responses regarding the modeling of switches in the internal system are similar to those regarding the modeling of circuit breakers, as indicated in Table 4.1-11 and Table 4.1-12. The majority of respondents model higher-voltage switches for greater than 95 percent of their systems; lower-voltage switches are generally modeled for less of their systems. By comparing the response summaries in Table 4.1-9 and Table 4.1-10 to those in Table 4.1-11 and Table 4.1-12, we can see that breakers are modeled more often than switches for each voltage range for both RC and other respondents. This is most likely because some entities that include breakers in their models choose not to include disconnect detail in their power system models as a matter of practice.

From these observations, we may conclude that:

1) Survey respondents model breakers and switches in more detail at higher voltages than at lower voltages.
2) Survey respondents model a smaller percentage of their switches than their breakers.

Generator Step-Up Transformer Modeling

Eighty-eight percent (38 out of 43) of survey respondents include at least some of their internal system generator step-up (GSU) transformers in their internal network models. This includes 100 percent (17 out of 17) of RC respondents and 81 percent (21 out of 26) of the other respondents. Table 4.1-13 summarizes the criteria used by the RC and other respondents to determine whether or not a GSU is modeled in their internal network model.

GSU Modeling Criteria for Internal Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Other	**Total**
Based on available telemetry data (SCADA, ISN, etc.)	X	X	X	X	X	X	X	X		X	X	X	X					10	**22**
Based on unit size (MVA)	X	X	X	X	X	X	X	X	X									11	**20**
Other(s)	X	X	X	X					X					X	X	X	X	3	**12**
Based on unit type (coal, nuke, hydro, etc.)	X																	3	**4**
Based on the size of the auxiliary load																		1	**1**

Table 4.1-13 — Modeling Criteria for Internal System Generator Step-Up Transformers

From Table 4.1-13 we see that the most common criterion used to determine whether or not to model a GSU for an internal system generator is the "availability of telemetry data," which was selected by 58 percent (22 out of 38) of the respondents that model internal GSUs. This includes 71 percent (12 out of 17) of the RC respondents and 47 percent (10 out of 21) of the other respondents. This was closely followed by "based on the unit size (MVA)" which was selected by 52 percent (20 out of 38) of the respondents that model internal GSUs. This includes 53 percent (9 out of 17) of the RC respondents and 52 percent (11 out of 21) of the other respondents.

Forty-four percent (19 out of 43) of the survey respondents model GSUs for at least some external generating units in their external system models. This includes 59 percent (10 out of 17) of the RC respondents and 38 percent (10 out of 26) of the other respondents. Table 4.1-14 summarizes the criteria that RC and other respondents use to determine whether or not a GSU for an external generating unit will be included in their external network model.

External GSU Modeling Criteria	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Other	**Total**
Based on available telemetry data	X	X	X	X	X	X					NR	NR	NR	NR	NR	NR	NR	6	**12**
Based on unit size (MVA)	X	X	X	X			X				NR	NR	NR	NR	NR	NR	NR	3	**8**
Other(s)	X							X	X	X	NR	NR	NR	NR	NR	NR	NR	2	**6**

Table 4.1-14 — Criteria Used for Modeling External Network GSUs

From Table 4.1-14 we see that the most common criterion used to determine whether or not to model a GSU for an external system generator is the "availability of telemetry data," which was selected by 63 percent (12 out of 19) of the respondents that model external GSUs. This includes 60 percent (6 out of 10) of the RC respondents and 67 percent (6 out of 9) of the other respondents. This was followed by "based on the unit size (MVA)," which was selected by 42 percent (8 out of 19) of the respondents that model internal GSUs. This includes

50 percent (5 out of 10) of the RC respondents and 33 percent (3 out of 9) of the other respondents that model external GSUs.

It is worth noting that survey respondents favor the same criteria for determining whether or not to model GSUs for both internal and external units. However, both RC respondents and the other respondents model external GSUs to a lesser extent. This is probably because 1) the required modeling information for the external units and their GSUs is more difficult to acquire, and 2) the level of detail required in external models is generally less than that required in internal models.

Generator Auxiliary Load Modeling

Seventy-one percent (29 out of 41) of the respondents model at least some of their internal generating unit auxiliary loads in their internal network models. This includes 71 percent (12 out of 17) of the RC respondents and 71 percent (17 out of 24) of the other respondents. Table 4.1-15 summarizes the criteria used by the RC and other respondents to determine which internal generating unit auxiliary loads to model.

Criteria Used to Determine Which Generating Unit Auxiliary Loads to Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Based on available telemetry data	X	X	X	X		X							NR	NR	NR	NR	NR	10	**15**
Based on unit size (MVA)	X	X	X	X	X				X	X			NR	NR	NR	NR	NR	3	**10**
Based on available MW/Mvar measurements	X	X	X	X	X	X	X						NR	NR	NR	NR	NR	3	**10**
Based on the size of the auxiliary load	X	X				X	X	X					NR	NR	NR	NR	NR	3	**8**
Other(s)	X		X		X						X	X	NR	NR	NR	NR	NR	3	**8**
Based on unit type (coal, nuke, etc.)		X		X				X					NR	NR	NR	NR	NR	1	**4**

Table 4.1-15 — Criteria for Internal Generator Auxiliary Load Modeling

From Table 4.1-15 we see that the most common criterion used to determine whether or not to model generator auxiliary loads for internal system generators is “available telemetry data.” This criterion was selected by 52 percent (15 out of 29) of the respondents that model internal generator auxiliary loads. This includes 42 percent (5 out of 12) of the RC respondents and 59 percent (10 out of 17) of the other respondents. The second and third most common criteria used by the respondents were “unit size” and “available MW/Mvar” measurements. Both of these criteria were selected by 34 percent (10 out of 29) of the respondents which included 58 percent (7 out of 12) of the RC respondents and 18 percent (3 out of 17) of the other respondents.

Only 15 percent (6 out of 41) of the respondents model external generator auxiliary loads in their external network models. This includes 24 percent (4 out of 17) RC respondents and 8 percent (2 out of 24) of the other respondents.

Unit Mvar Capability Curves

Sixty-eight percent (30 out of 44) of the survey respondents reported that they model internal generating unit Mvar capability curves in their internal models. This includes 82 percent (14 out of 17) of the RC respondents and 59 percent (16 out of 27) of the other respondents. It is surprising that 3 of the 17 RCs do not include generating unit capability curves in view of the importance of these curves in determining Mvar reserves and improving voltage calculations by applications such as contingency analysis.[10]

Table 4.1-16 summarizes the methodologies used by respondents that model internal network model generator Mvar capability curves.

[10] RTBPTF did not contact the RCs who were not modeling generating unit Mvar capability curves to determine why they do not model them.

Internal Generating Unit Mvar Capability Curve Development	**RC01**	**RC02**	**RC03**	**RC04**	**RC05**	**RC06**	**RC07**	**RC08**	**RC09**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**RC17**	**Other**	**Total**
Based on original design curves	X	X		X	X									X	NR	NR	NR	13	**18**
Provided by the unit owners	X	X		X	X	X		X	X	X	X	X			NR	NR	NR	3	**13**
Other(s)	X	X	X				X								NR	NR	NR	1	**5**
Approximated based on unit type, size, etc.	X		X										X		NR	NR	NR	2	**5**

Table 4.1-16 — Methodologies Used to Develop Internal Unit Mvar Capability Curve Models

From Table 4.1-16 we see that the most common criterion used to develop internal generator Mvar capability curves was "based on original design curves." Sixty percent (18 out of 30) of the survey respondents selected this response. This includes 36 percent (5 out of 14) of the RC respondents and 81 percent (13 out of 16) of the other respondents that model internal generator Mvar capability curves. It is not surprising that most of the respondents that chose this answer are the "other" (non-RC) respondents because they would be more likely to be unit owners.

Forty-three percent (13 out of 30) of the respondents base their internal generator Mvar capability models on data provided by the generating unit owners. This includes 71 percent (10 out of 14) of the RC respondents and 19 percent (3 out of 16) of the other respondents that model internal capability curves. It is not surprising that most of the respondents that chose this response were RCs because in many cases they do not own generation and would need to rely on information provided by the asset owners.

Table 4.1-18 summarizes the responses to the question "how do you verify the accuracy of the Mvar capability curves?" There were 30 respondents to this question, which included 14 RC respondents and 16 other respondents.

Verifying the Accuracy of Unit Mvar Capability Curves	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
We do not verify their accuracy									X	X	X	X	X	X	NR	NR	NR	9	**15**
Periodic generator tests at plants	X	X	X	X	X		X	X							NR	NR	NR	6	**13**
Actual response monitoring	X	X	X												NR	NR	NR	2	**5**
Other(s)				X	X	X									NR	NR	NR	2	**5**

Table 4.1-17 — Methodologies Used to Verify Internal Model Mvar Capability Curves

Table 4.1-17 summarizes the survey responses regarding how the respondents that model their internal generator Mvar capability curves verify the accuracy of these curves. Fifty percent (15 out of 30) of the respondents that model them do not verify their accuracy at all. This includes 43 percent (6 out of 14) of the RC respondents and 56 percent (9 out of 16) of other respondents. Of those 15 respondents that do verify their Mvar capability curve accuracy, 87 percent (13 out of 15) of the respondents perform periodic tests at generating plants. The remainder of those who test use “other” means.

Table 4.1-18 summarizes the methodologies used by respondents that model external network model generator Mvar capability curves.

Fifty-one 50 percent (22 out of 43) of the survey respondents report that they model generator Mvar capability curves in their external models. This includes 71 percent (12 out of 17) of the RC respondents and 38 percent (10 out of 26) of the other respondents. Table 4.1-18 summarizes how the respondents develop their external model generating unit Mvar capability curves.

External Generating Unit Mvar Capability Curve Development	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Other	**Total**
Approximated based on units of similar type, size, etc.	X	X	X	X	X	X	X	X					NR	NR	NR	NR	NR	8	**16**
Provided by the unit owners	X								X	X	X		NR	NR	NR	NR	NR	2	**6**
Other(s)									X			X	NR	NR	NR	NR	NR	1	**3**

Table 4.1-18 — Methodologies Used to Develop External Model Mvar Capability Curves

Seventy percent (16 out of 22) of the respondents that model external unit capability curves report that they model external generating unit Mvar capability curves using “approximations based on the generator unit characteristics such as MVA size, type, etc.” This includes 67 percent (8 out of 12) of the RC respondents and 80 percent (8 out of 10) of the other respondents. This is likely because the curve data are more difficult to obtain from the external entities that own the units. In addition, modeling accuracy is not considered a significant issue in most cases because generating units in the external model are usually electrically distant from the internal system. Consequently, inaccuracies in the Mvar capability curves will not usually have a significant impact on the voltages computed by the network applications in the internal portion of the model.

Verifying Transmission Line Characteristics

There were 43 respondents to the survey questions related to the verification of transmission-line characteristics. The respondents included 16 RCs and 27 other respondents.

Table 4.1-19 summarizes the responses and the breakdown of the respondents. Only 46 percent (20 out of 43) of the respondents verify the electrical characteristics of their transmission lines. This includes 50 percent (8 out of 16) of the RC respondents and 44 percent (12 out of 27) of other respondents.

Do you Verify T-Line Characteristics?	RC	Other	Total
No	8	15	**23**
Yes	8	12	**20**
Totals	16	27	**43**

Table 4.1-19 — Verification of Transmission-Line Limits

Table 4.1-20 shows the methodology used by each of the 20 respondents that verify transmission line characteristics. The most common method that is used by 65 percent (13 out of 20) of the respondents that verify transmission line characteristics was “based on voltage and flow readings at each end of the line.” This includes 38 percent (3 out of 8) of the RC respondents and 83 percent (10 out of 12) of the other respondents that verify transmission-line characteristics. The second most common method used by 30 percent (6 out of 20) of the respondents was “based on field data and planning models.” These respondents included 3 RCs and 3 other respondents. Surprisingly, only one respondent uses state estimator results. However, respondents may have interpreted “based on voltage and flow readings at each end of the line” as using state estimator readings. Note that only two respondents use actual field tests with special field equipment.

Methods used to Verify T-Line Characteristics	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Based on voltage and flow readings on each end of the line	X	X					X		NR	NR	NR	NR	NR	NR	NR	NR	NR	10	**13**
Based on field data and planning models				X	X			X	NR	NR	NR	NR	NR	NR	NR	NR	NR	3	**6**
Based on data from transmission owner	X		X			X			NR	NR	NR	NR	NR	NR	NR	NR	NR		**3**
Based on field tests with special testing equipment		X							NR	NR	NR	NR	NR	NR	NR	NR	NR	1	**2**
Based on reliable state estimator results									NR	NR	NR	NR	NR	NR	NR	NR	NR	1	**1**

Table 4.1-20 — Methods used to Verify Transmission-Line Characteristics

Transmission Line Real-Time Limits

Nearly 80 percent (33 out of 42) of the respondents reported that their EMS network models support use of “real-time” limits and/or multiple limit sets based on temperatures or seasons for transmission lines. These 33 respondents included 16 RCs and 17 other respondents. Of the 33 respondents that have this capability, 88 percent (29 out of 33) of all respondents make use of these features. This includes 88 percent (14 out of 16) of the RC respondents and 88 percent (15 out of 17) of the other respondents that have this capability. Table 4.1-21 shows how each of the respondents implements real-time limits and/or multiple limit sets for transmission lines.

Methods Used to Implement Real Time Limits	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Discrete limit sets manually selected by operators	X	X	X	X								X	X	X	NR	NR	NR	10	**17**
Dynamically computed from weather variables	X	X	X			X	X			X					NR	NR	NR	3	**9**
Discrete limit sets automatically selected	X	X			X	X	X								NR	NR	NR	1	**6**
Telemetered limits from real-time line rating devices	X		X	X					X						NR	NR	NR		**4**
Others		X			X			X			X				NR	NR	NR	1	**5**

Table 4.1-21 — Methods used to Implement Real-Time Limits

Fifty-eight percent (17 out of 29) of all the respondents that have implemented real-time limits and/or multiple limit sets say that they use "discrete limit sets that are manually selected by the operators" for at least some of their transmission lines. This includes 50 percent (7 out of 14) of the RC respondents and 67 percent (10 out of 15) of the other respondents. Thirty-one percent (9 out of 29) of the respondents use limits that are "dynamically computed from weather variables." This includes 42 percent (6 out of 14) of the RC respondents and 20 percent (5 of 15) of the other respondents. The acquisition of telemetered limits from real-time rating devices was only used by 14 percent (4 out of 29) of the respondents, which included 29 percent (4 of 14) of the RC respondents and none of the other respondents.

Table 4.1-22 shows the number of limit sets used by the 26 respondents that report that they use of multiple limit sets.

No. Of Limit Sets Used for Lines	RCs	Others	All
2	5	5	10
3	3	3	6
4	2	2	4
7		1	1
8		1	1
16	2		2
20	1		1
24		1	1
Total	**13**	**13**	**26**[11]

Table 4.1-22 — Number of Limit Sets Used for Transmission Lines

[11] These figures do not add up to 29. Apparently some of the respondents (1 RC and 3 other respondents) that said they use multiple limit sets but failed to answer the follow-up questions related to the number of sets used.

The number of limit sets used by the survey respondents varies widely from 2 to 24. It is interesting to note that 38 percent (10 out of 26) of the respondents use only 2 limits sets. This includes 35 percent (5 out of 13) of the RC respondents and 38 percent (5 out of 13) of the other respondents. Seventy-seven percent (20 out of 26) of all respondents and 77 percent (10 out of 13) of the RC respondents use 4 or fewer limit sets.

Transformer Real-Time Limits

Seventy-six percent (32 out of 42) of survey respondents have network models that support the use of real-time limits and/or multiple limit sets based on temperatures or seasons for transformers. This includes 94 percent (16 out of 17) of the RC respondents and 65 percent (17 out of 26) of the other respondents. Of the 33 respondents that have this capability, 76 percent (25 of out 33) are making use of these features. This includes 75 percent (12 out of 16) of the RC respondents and 82 percent (14 out of 17) of the other respondents.

Table 4.1-23 shows the number of limit sets used for transformers by each of the 25 respondents that employ them. As with transmission lines, the number of limit sets used by the respondents for transformers varies widely from 2 to 24 limit sets.

Number of Limit Sets Used for Transformers	RC	Other	All
2	4	6	10
3	5	2	7
4	1	1	2
7	1	1	2
8		1	1
16	2		2
24		1	1
Total	**13**	**12**[12]	**25**

Table 4.1-23 — Number of Transformer Model Limit Sets

Forty percent (10 out of 25) of the respondents, which include 31 percent (4 out of 13) of the RC respondents, use only 2 limit sets. Seventy-six percent (19 out of 25) of the respondents, including 77 percent (10 out of 13) of the RC respondents and 75 percent (9 out of 12) of the other respondents that use multiple limit sets use 4 or fewer sets.

[12] One of the “Other” respondents that uses multiple limit sets did not provide information on how many they use.

Bus Load Modeling

Forty respondents, which include 17 RC respondents and 23 other respondents, answered questions related to the busload modeling capabilities of their EMS network models. Table 4.1-24 summarizes their responses.

EMS Network Model Bus Load Modeling Features and Usage	RCs		Others	
	Supported	Used	Supported	Used
Mapping of real-time load measurements to load models	15	15	17	14
Non-conforming Loads	12	11	14	10
Hourly Loads by day of week and hour	12	9	14	12
Models adapt based on state estimator solution	13	10	9	6
Holiday/Abnormal Day load modeling	11	2	10	2
Hourly Mvar or power factor by day of week and hour	7	5	12	7
Input from the System Load Forecast application	9	6	6	3
MW/Mvar Bus loads vary as function of bus voltage	8	2	6	1
Individual load profile from an external application for an area, bus, feeder, etc.	5	3	4	3

Table 4.1-24 — Load Model Features Supported/Used

Eighty percent (32 out of 40) of the respondents, including 88 percent (15 out of 17) of the RC respondents and 74 percent (17 out of 23) of the other respondents, have the capability to map real-time measurements to the load modeled in their network models. Of those that have this capability, 91 percent (29 out of 32) of the respondents, including 100 percent (15 out of 15) of the RC respondents and 74 percent (14 out of 23) of other respondents, utilize this feature.

Fifty-five percent (22 out of 40) of the respondents, which includes 76 percent (13 out of 17) of the RC respondents and 39 percent (9 out of 23) of the other respondents, have EMS load models that adapt over time based on the state estimator solution. Of the respondents that have this feature, 72 percent (16 out of 22) of the respondents, which include 77 percent (10 out of 13) of the RC respondents and 67 percent (6 out of 9) of the other respondents, make use of it.

Only 35 percent (14 out of 40) of respondents' network models, including 47 percent (8 out of 17) of the RC respondents and 26 percent (6 out of 23) of the other respondents, support voltage-sensitive loads. Of the 14 respondents whose models support this feature, only 21 percent (3 out of 14) actually make use of it.

Table 4.1-25 and Table 4.1-26 below show the frequency of internal and external bus load model updates. Sixty-eight percent (28 out of 41) of the respondents, which includes 65 percent (11 out of 17) of the RC respondents and 71 percent (17 out of 24) of the other respondents, report that the frequency of updates for their internal bus load models is "other." Seventy percent (29 out of 41) of the respondents, which includes 65 percent (11 out of 17) of the RC respondents and 75 percent (18 out of 24) of the other respondents, report that the frequency for updating their external load models is “other.” It was determined from the survey comments that most of the survey respondents interpreted the “other” category to mean “as needed.” A few respondents answered “infrequently” and “never.”

Respondent	Annually	Monthly	Weekly	Other	**Total**
RCs	4	1	1	11	**17**
Others	5		2	17	**24**
All	9	1	3	28	**41**

Table 4.1-25 — Internal Bus Load Model Update Frequency

Respondent	Annually	Monthly	Weekly	Other	**Total**
RCs	6			11	**17**
Others	5		1	18	**24**
All	11		1	29	**41**

Table 4.1-26 — External Bus Load Model Update Frequency

External Network Models

Table 4.1-27 summarizes the methods used by the survey respondents to determine which power system elements (e.g., buses, lines, transformers, generators, etc.) to include in their external network models. There were 43 respondents to this section of the survey, which includes 17 RC respondents and 26 other respondents.

Methods Used to Determine Power System Elements in the External Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Engineering judgment	X	X	X	X	X	X		X	X	X		X	X	X	X	X	X	9	**24**
System planning studies	X	X	X	X			X		X	X								9	**16**
Off-line modeling tools	X	X	X				X	X			X							10	**16**
Other	X	X			X	X												2	**6**
External modeled explicitly				X														2	**3**

Table 4.1-27 — Methods used to Determine External Model Elements

From Table 4.1-27 we see that 59 percent (10 out of 17) of the RCs use multiple methods to determine the elements to include in their external models, and 41 percent (seven out of 17) rely on just one method. Thirty-five percent (6 out of 17) of the RC respondents state that they rely solely on “engineering judgment” to determine the elements to be included in their external models. Thirty-five percent (9 out of 26) of other respondents report that they use “engineering judgment” and/or system planning studies, and 38 percent (10 out of 26) use other off-line modeling tools.

It was very surprising that 35 percent (6 out of 17) of RCs use "engineering judgment" as the sole means of determining what to include in their external models. Seventeen percent (4 out of 24) of the other respondents listed "engineering judgment" as their only means for determining what to include in their external models. Relying solely on engineering judgment to build an external network model is not desirable because it is not always intuitively obvious how much of an interconnection needs to be included in an external model to produce accurate contingency analysis results. Relying entirely on engineering judgment introduces the risk that the external model will be either excessively small or excessively large. If the external model is too small, it can cause erroneous results in real-time contingency analysis, on-line power flow studies, and other applications. If the model is too large, the applications may require significantly more computing resources to arrive at a solution, and the model will require more maintenance resources to keep it current (or it will not be maintained at all).

Table 4.1-28 summarizes the survey results regarding the frequency with which respondents make major changes in their external network models.

Frequency of Major External Model Updates	RC	Others	All
As needed	11	5	16
Annually	3	8	11
N/A		4	4
Infrequently		2	2
Monthly	1	1	2
Depends		1	1
5 years		1	1
Quarterly	1		1
Not done in years		1	1
6-8 weeks	1		1
All	**17**	**23**	**40**

Table 4.1-28 — Frequency of Major External Model Updates

We see that 40 percent (16 out of 40) of the respondents, which includes 65 percent (11 out of 17) of the RC respondents and 22 percent (5 out of 23) of the other respondents, make major changes to their external models as needed. Unfortunately, the survey did not ask them what the average frequency of the "as needed" updates was. Twenty-seven percent (11 out of 40) of the respondents, which includes 18 percent (3 out of 17) of the RC respondents and 35 percent (8 out of 23) of the other respondents, said they make major changes to their external models on an annual basis.

It is difficult to draw any strong conclusions from the responses summarized in Table 4.1-28 except that the external model update frequencies vary widely.

Table 4.1-29 shows the reported starting point for creating (or making additions to) existing external models. There were 41 respondents to this question, including 17 RC respondents and 24 other respondents.

Starting Point for Creating or Adding to the External Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
System planning bus/branch model	X	X		X				X	X	X	X	X	X	X	X	X	X	18	**31**
Detailed model from a previous EMS	X	X				X	X											3	**7**
Others				X	X													4	**6**
Detailed EMS model in proprietary non-vendor format	X	X																1	**3**
CIM XML models from the surrounding entities	X	X	X																**3**
Detailed EMS models in proprietary vendor formats	X		X																**2**

Table 4.1-29 — Starting Point for Creating or Making Additions to the External Model

Seventy-six percent (31 out of 41) of respondents, including 76 percent (13 out of 17) of the RC respondents state that the starting point for creating or making additions to their external models is a system planning model (i.e., a bus-branch model with no breaker/switch detail). It is interesting to note that only 3 of the 41 respondents, all of which are RCs, report that the starting point for their external model (or external model additions) was CIM XML[13] models provided by neighboring entities.

CIM XML is not widely used for building and/or maintaining models for a number of reasons. First, the CIM XML modeling language is relatively new and still evolving. Consequently, some entities with older EMSs can only provide model "dumps" in system planning formats (e.g., PSS/E, GE, etc.) or other proprietary EMS vendor formats. Moreover, the use of CIM XML files for building an external model is still problematic because there are few tools, if any, available to merge a CIM XML model with an existing model. The topic of CIM XML will be discussed further in Section 4.2, Modeling Practices and Tools, of this report.

Eighty percent (33 out of 41) of survey respondents, including 100 percent (17 out of 17) of the RC respondents and 67 percent (16 out of 24) of the other respondents, have at least some real-time analog telemetry linked to their external network models. Table 4.1-30 summarizes this information.

[13] CIM XML has been adopted by NERC Data Exchange Working Group (DEWG) to be the format for exchanging models among transmission system operators.

Have Real-time Analogs Linked to External Model?	RCs	Others	All
None		8	8
Some	17	16	33
Total	**17**	**24**	**41**

Table 4.1-30 — Entities with Real-Time Analog Points in their External Models

Seventy-one percent (29 out of 41) of survey respondents, including 82 percent (14 out of 17) of the RC respondents and 63 percent (15 out of 24) of the other respondents, report that they have at least some real-time status point telemetry linked to their external network models. Table 4.1-31 summarizes this information.

Have Real-time Status Points linked to External Model	RCs	Others	All
None	3	9	12
Some	14	15	29
Total	**17**	**24**	**41**

Table 4.1-31 — Entities with Real-Time Status Points in their External Models

It is worth noting that three RC respondents report that they have no real-time status points in their external models.[14]

The average density of real-time analog and status points linked to the external model is reflected by the ratios of analog and status points in the external model to the number of external model buses. These ratios were computed for the survey respondents that provided sufficient information and are shown in Table 4.1-32, Table 4.1-33, Table 4.1-34, and Table 4.1-35.[15]

The low analog-to-bus ratios in the tables (i.e., fewer than 2 analogs per bus for most of respondents) show that many of the buses in these respondents' external models are likely to be measurement unobservable, from a state estimator perspective, without the use of pseudo-measurements. The low external-status-point-to-external-bus ratios for many respondents (i.e., fewer than 1 status point per bus) indicate that many external buses do not have telemetered breaker/switch information, which implies a bus-branch type external model (i.e., a planning model) for many buses. These ratios may explain why many of the respondents state that they will be adding analog and status points to their external models in the coming year.

[14] These RCs were not contacted to verify the accuracy of their responses.

[15] These ratios could only be computed for the survey respondents that provided both the number of external model buses and the numbers of telemetered analog and status points in their external models.

The lack of real-time telemetry data in the external model was one of the contributing factors in the August 2003 blackout. MISO was using a static bus-branch network model in parts of its external model. When the Stuart-Atlanta 345-kV line tripped (monitored by the PJM RC), MISO's state estimator did not know that the line had gone out of service. This led to a data mismatch that prevented MISO's state estimator from computing a solution that could be used by its real-time contingency analysis application. Without real-time contingency analysis, MISO's ability to see that its system was in danger was greatly compromised.[16]

Resp	No of External Buses	Tel Analog Meas in External	Ext Analog to External Bus Ratio
RC01	15	70	4.67
RC02	9	40	4.44
RC03	60	253	4.22
RC04	445	1,174	2.64
RC05	5,580	11,044	1.98
RC06	17,873	32,476	1.82
RC07	638	1,039	1.63
RC08	1,577	2,153	1.37
RC09	4,837	5,376	1.11
RC10	300	177	0.59
RC11	463	242	0.52
RC12	3,420	936	0.27
RC13	1,575	220	0.14
Count	13	13	13
Average	2,830	4,246	1.95
Median	638	936	1.63
Std Dev	4,894	9,034	1.59
Max	17,873	32,476	4.67
Min	9	40	0.14

Table 4.1-32 — External-Telemetered-Analog-to-External-Bus Ratios for RCs

[16] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 18.

Resp	No. of External Buses	Tel Status Meas in External	Ext Status Pt to External Bus Ratio
RC01	638	2,814	4.41
RC02	9	37	4.11
RC03	15	60	4.00
RC04	5,580	16,496	2.96
RC05	17,873	33,207	1.86
RC06	60	102	1.70
RC07	463	623	1.35
RC08	1,577	1,994	1.26
RC09	4,837	2,382	0.49
RC10	300	129	0.43
RC11	3,420	924	0.27
RC12	445	72	0.16
Count	12	12	12
Average	2,935	4,903	1.92
Median	551	774	1.52
Std Dev	5,097	10,023	1.58
Max	17,873	33,207	4.41
Min	9	37	0.16

Table 4.1-33 — External-Telemetered-Status-Point-to-External-Bus Ratios for RCs

Resp	No of External Buses	Tel Analog Meas in External	Ext Analog to External Bus Ratio
R01	10	334	33.40[17]
R02	630	3,000	4.76
R03	1	4	4.00
R04	1,073	2,545	2.37
R05	2,190	2,751	1.26
R06	40	50	1.25
R07	167	163	0.98
R08	2,505	2,340	0.93
R09	16,138	11,385	0.71
R10	7,100	3,493	0.49
R11	3,090	1,500	0.49
R12	1,722	424	0.25
R13	1,906	423	0.22
R14	504	79	0.16
R15	420	60	0.14
R16	1,952	206	0.11
R17	2	0	0.00
Count	17	17	17
Average	2,321	1,692	3.03
Median	1,073	423	0.71
Std Dev	3,971	2,789	7.94
Max	16,138	11,385	33.40
Min	1	0	0.00

Table 4.1-34 — External-Telemetered-Analog-to-External-Bus Ratios for Non-RCs

[17] This value looks extremely high and may be a data submission error. RTBFTF did not contact the respondent for verification.

Resp	No. Of External Buses	Tel Status Meas in External	Ext Status Pt to External Bus Ratio
R01	10	378	37.80
R02	630	6,000	9.52
R03	1,073	3,173	2.96
R04	167	146	0.87
R05	2,505	1,640	0.65
R06	16,138	9,535	0.59
R07	3,090	1,000	0.32
R08	1,722	517	0.30
R09	7,100	1,832	0.26
R10	40	10	0.25
R11	2,190	535	0.24
R12	420	50	0.12
R13	1,952	157	0.08
R14	504	6	0.01
R15	1,906	0	0.00
R16	1	0	0.00
Count	16	16	16
Average	2,466	1,561	3.37
Median	1,398	448	0.28
Std Dev	4,055	2,656	9.48
Max	16,138	9,535	37.80
Min	1	0	0.00

Table 4.1-35 — External-Telemetered-Status-Point-to-External-Bus Ratios for Non-RCs

Table 4.1-36 summarizes the types of analog points used in the external models of the 33 respondents that have analogs in their external models. The respondents include 17 RCs and 16 other respondents.

Analog Types Linked to External Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
MW	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	16	**32**
Mvar	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X	16	**32**
KV	X	X	X	X	X	X	X		X	X	X	X	X	X	X	X	X	15	**31**
LTC tap positions	X	X	X	X	X			X										4	**10**
Phase-angle regulating transformer taps				X	X			X										2	**5**
Amps	X						X											2	**4**
Line/TX ratings		X				X													**2**
Others	X		X																**2**

Table 4.1-36 — Analog Types Linked to External Model

From the table we see that the MW, Mvar, and KV analog types were reported used in almost 100 percent of the external models because virtually all state estimators use those measurement types. LTC and phase angle regulating (PAR) transformer tap positions are used to a lesser extent. This is probably because some utilities do not have those types of devices on their transmission grids, which is, in turn, because state estimators provided by most vendors support the use of those types of analogs as inputs. PARs are more commonly seen in the northeastern areas of the Eastern Interconnection to mitigate undesirable flow patterns

Table 4.1-37 summarizes the responses regarding the criteria used to select the analog points that are linked to the external models of respondents that have analog points in their external models. There were 33 total respondents, including 17 RC respondents and 16 other respondents. The respondents overwhelmingly selected “engineering judgment” as the leading analog and status point selection criteria, followed by “all measurements above a certain kV level.” Only 3 respondents, 2 of which were RCs, use analytical tools to determine where measurements are needed.

Analog Selection for External Model	**RC01**	**RC02**	**RC03**	**RC04**	**RC05**	**RC06**	**RC07**	**RC08**	**RC09**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**RC17**	**Others**	**Total**
Engineering judgment	X	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	11	**27**
All meas. above a certain kV level	X		X				X	X	X	X	X	X						7	**15**
Other(s)			X	X	X	X												3	**7**
Off-line observability and/or sensitivity studies	X	X																1	**3**

Table 4.1-37 — Analog Selection Criteria used for External Models

Table 4.1-38 summarizes the responses regarding the criteria used to select the status points that are linked to the external models of respondents that have status points in their external models. There were 29 total respondents, including 14 RC respondents and 15 other respondents. The respondents overwhelmingly selected “engineering judgment” as the leading method for both the analog and status point selection criteria, followed by “all measurements above a certain kV level.” Only 3 respondents, 2 of which were reliability coordinators, use analytical tools to determine where measurements are needed.

Status Point Selection for External Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Engineering judgment	X		X	X	X	X	X	X			X	X	X	X	NR	NR	NR	10	**21**
Brought in all measurements above a certain kV level	X	X				X	X	X		X					NR	NR	NR	7	**13**
Other(s)		X	X	X	X										NR	NR	NR	4	**8**
Offline observability and/or sensitivity studies	X								X						NR	NR	NR	1	**3**

Table 4.1-38 — Status Point Selection Criteria used for External Models

Recommendations for New Reliability Standards

The RTBPTF recommends no new reliability standards for model characteristics because the Real-Time Tools Survey reveals that entities have significantly different practices for creating and maintaining models of the bulk electric system.

Recommendations for New Operating Guidelines

RTBPTF does not recommend developing operating guidelines related to model characteristics.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for model characteristics. All recommendations for additional analysis related to modeling issues are presented in Section 4.2, Modeling Practices and Tools.

Examples of Excellence

RTBPTF identified no examples of excellence related to Model Characteristics.

Section 4.2
Modeling Practices and Tools

Definition

The term “modeling practices” as used in the context of this report refers to the processes, procedures, and general methodologies used to build and/or maintain mathematical representations of the power system that are used by real-time applications such as the state estimator, contingency analysis, and on-line power flow. “Modeling tools” are the software applications used to build and/or maintain mathematical representations of the power system. They include any applications supplied by vendors, provided by third parties, or created in house.

Background

The *Outage Task Force Final Blackout Report* [18] identifies a number of modeling deficiencies that contributed to the August, 2003 blackout. For example, because MISO did not link real-time measurements to the external portion of its model, the resulting undetected outage of a key transmission line meant that MISO’s state estimator could not converge. Downstream applications that depend on the state estimator solution could therefore not produce accurate representations of the system condition.

Summary of Findings

RTBPTF considers the implementation of modeling practices and tools to be critical to real-time operations. Therefore, a considerable portion of the Real-Time Tools Survey and subsequent analysis were dedicated to examining the various power system network modeling practices and tools that respondents throughout the industry employ to build and maintain the power system models used by their real-time applications.

This analysis is divided into three subsections: power system model updates, data and information exchange, and modeling tools and utilities. The key findings in these areas are:

- Forty-three percent of all survey respondents, including 53 percent of the RC respondents, model future grid changes by using temporary, fictitious “dummy” switches that allow the new equipment element(s) to be switched into service and/or old equipment elements to be switched out of service when anticipated changes actually take place in the field. The dummy switches are removed on subsequent updates.

[18] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 18.

- Respondents report network model update frequencies ranging from 1- to 12-week intervals. Forty percent of all respondents, including 50 percent of the RC respondents, update their models on a weekly basis.

- Seventy-five percent of all respondents, including 82 percent of the RC respondents, formally document changes and updates to their network models.

- Fifty-six percent of all respondents, including 71 percent of the RC respondents, have some form of documented testing and quality assurance (QA) procedures for their network model changes. Surprisingly, some of the respondents, including a few RCs, place model changes on line with no prior testing.

- Sixty-one percent of all respondents, including 88 percent of the RC respondents, have documented procedures to communicate internal system changes to EMS network modeling personnel.

- Only 35 percent of the survey respondents have formal agreements and/or processes to notify and/or be notified by entities external to their reliability areas about transmission grid changes. Fifty-nine percent of the RC respondents have such processes and procedures. This is surprisingly low, especially for the RCs because of their responsibilities.

- Fifty-five percent of respondents have agreements and procedures for exchanging modeling data with external entities. Fifty-three percent of the RC respondents have such procedures.

- Only 29 percent of survey respondents have model merge utilities, and only 41 percent of the RC respondents have such tools. This means that 59 percent of the RCs have no tools and must use only manual means to incorporate new model additions into their existing models. This highlights a significant need for model merge tools to maintain large power system models.

- Forty-one percent of respondents have network reduction/equivalencing tools, and 47 percent of the RC respondents have these tools. These tools are typically used for external model creation.

- Less than 25 percent of respondents say they have used CIM XML files to either import models from other entities or export their model for use by other entities. Information from the model characteristics section of the survey seems to imply that less that 10 percent of the respondents are using CIM XML files for external model updates.

The subsections that follow present a detailed analysis of the survey data on which the above findings are based.

Power System Model Updates

The survey collected information related to several areas of power system model maintenance, including methods of modeling of future grid changes, the frequency with which production network models are updated, documentation of network model changes, automatic logging of network model changes, QA and testing of network model changes, and testing of changes before they are put on line.

Modeling of Future Grid Changes

Table 4.2-1 summarizes respondents' reported methods of integrating future grid changes into network models in a timely manner. There were 40 respondents, including 17 RC respondents and 23 other respondents.[19]

How Do You Model Future Grid Changes?	RCs	Others	**Total**
Add future elements and "dummy" switches to connect/disconnect future/old equipment	9	8	**17**
Perform an immediate database update on-line to reflect the database changes	5	5	**10**
Perform changes on backup and fail over	3	6	**9**
Perform immediate partial model update on line		4	**4**
All	**17**	**23**	**40**

Table 4.2-1 — Modeling Future Network Model Changes

Respondents chose one of four methods for modeling future network changes. Forty-three percent (17 out of 40) of all respondents, including 53 percent (9 out of 17) of the RC respondents and 35 percent (9 out of 23) of the other respondents, model future grid elements by using temporary "dummy" switches that allow new equipment element(s) to be switched into service and/or the old equipment element(s) to be switched out of service when anticipated changes actually take place in the field. These temporary switches and other elements are subsequently removed when a new database is put in service that incorporates all of the grid changes. Twenty-five percent (10 out of 40) of respondents, including 29 percent (5 out of 17) of the RC respondents and 22 percent (5 out of 23) of the other respondents, perform immediate database updates on line to reflect the addition/removal of equipment in the field when the equipment is actually placed into/out of service. Twenty-two percent (11 out of 40) of the respondents, including 18 percent (3 out of 17) of the RC respondents and 26 percent (6 out of 23) of the other respondents, make the changes in their backup system databases and then fail over to the new database when the

[19]Respondents without models were not included in the table.

equipment in the field goes into or out of service. Ten percent (4 out of 40), including 0 percent (0 out of 17) of the RC respondents and 17 percent (4 out of 23) of the other respondents, perform immediate partial model updates on line.

The respondents' choices of methods appear to depend largely on their EMSs' database modeling capabilities (i.e., features provided by the EMS vendor) and the sizes of their databases. Respondents that have on-line database-change capabilities use them (see the "Modeling Tools and Utilities" subsection below). Respondents without on-line database editing capabilities use one of the other two methods identified in Table 4.2-1; the majority of RC respondents without on-line editing capabilities favor the "dummy switch" approach for modeling future system changes.

Frequency of Network Model Updates

Table 4.2-2 summarizes the survey responses regarding frequency of production network model updates. There were a total of 40 respondents to this question, including 16 RC respondents and 24 other respondents.

Network Database Update Frequency	RC	Others	Total
Weekly	8	8	**16**
3 Weeks	2	3	**5**
Monthly	2	4	**6**
6 Weeks	1		**1**
12 Weeks	3	2	**5**
As needed		7	**7**
Total	**16**	**24**	**40**

Table 4.2-2 — Production Network Model Update Frequency

Respondents report network model update frequencies ranging from 1- to 12-week intervals, with unscheduled updates performed "as needed." Forty percent (16 out of 40) of the respondents, including 50 percent (eight out of 16) of the RC respondents and 33 percent (8 out of 24) of the other respondents, update their models weekly. Twenty-eight percent (11 out of 40) of respondents, including 25 percent (4 out of 16) of the RC respondents and 29 percent of the other respondents, update their models every 3 to 4 weeks. Respondents with markets report less frequent updates, most likely because of the complexities of market-related applications, the larger model sizes, and the associated auditing requirements.

Documentation of Network Model Changes

Table 4.2-3 summarizes the survey responses regarding documentation of network model changes. There were 40 respondents to this question, including 17 RC respondents and 23 other respondents.

Are Network Model Changes and Updates Formally Documented?	RC	Other	All
No	3	7	10
Yes	14	16	30
Totals	**17**	**23**	**40**

Table 4.2-3 — Formal Documentation of Network Model Changes

Seventy-five percent (30 out of 40) of the respondents, including 82 percent (14 out of 17) of the RC respondents and 70 percent (16 out of 23) of the other respondents, formally document the changes and updates made to their network models. All RCs that operate in markets formally document their network model changes, as would be expected.

Automatic Logging of Network Model Changes

Table 4.2-4 summarizes the survey responses regarding the automatic logging of network model changes. There were 40 respondents to this question, including 17 RC respondents and 23 other respondents.

Are Network Model Changes Automatically Logged by Modeling Tools?	RC	Other	All
No	11	18	29
Yes	6	5	11
Totals	**17**	**23**	**40**

Table 4.2-4 — Automatic Logging of Network Model Changes

Only 27 percent (11 out of 40) of respondents, including 35 percent (6 out of 17) of the RC respondents and 22 percent (5 out of 23) of the other respondents, have modeling tools that automatically log changes made to their network models. The responses summarized in Table 4.2-3 and Table 4.2-4 seem to imply that those that document network model changes do so largely manually.

Quality Assurance and Test Procedures for Network Model Changes

Table 4.2-5 summarizes survey responses related to documented model testing and quality assurance (QA) procedures. There were 39 respondents for these questions, including 17 RC respondents and 22 other respondents.

Has documented model change testing & QA procedures	RC	Other	All
No	5	12	17
Yes	12	10	22
Totals	**17**	**22**	**39**

Table 4.2-5 — Documented Model Testing and QA Procedures

Fifty-six percent (22 out of 39) of respondents, including 71 percent (12 out of 17) of the RC respondents and 45 percent (10 out of 22) of the other respondents, indicate that they have some form of documented testing and QA procedures for their network model changes. All of the RC respondents that operate in markets have these procedures, as one would expect. It is surprising that 29 percent (5 out of 17) of the RC respondents have no documented network model testing and quality assurance procedures.

Testing Model Changes Prior to Putting Model On-Line

Table 4.2-6 summarizes the survey responses related to testing network models before placing them on line in the production environment. There were a total of 39 respondents to these questions, including 17 RC respondents and 22 other respondents.

Model Change Testing Methodologies	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Development EMS with live data	X	X	X	X	X	X	X	X	X	X	X	X						10	**22**
Development EMS with no live data	X	X	X										X	X	X			1	**7**
Place on line with no tests, verify on-line																X	X	11	**13**
Test on a DTS						X												4	**5**
Use study power flow and/or study contingency analysis to test changes					X														**1**
Test using off-line model															X				**1**
Test on backup system using real-time telemetry				X															**1**

Table 4.2-6 — Model Change Testing Methodologies

Fifty-six percent (22 out of 39) of respondents, including 71 percent (12 out of 17) of the RC respondents and 45 percent (10 out of 22) of the other respondents, test their network models on a development (i.e., test bed) system that allows testing with live SCADA data. Only 33 percent (13 out of 39) of respondents, including 12 percent (2 out of 17) of the RC respondents and 50 percent (11 out of 22) of the other respondents, place their model changes on the production system with no testing prior to putting the models on line. They test their models on line after they are put into production.

A higher percentage of RCs than other respondents perform testing with live data on a development system prior to putting their models on-line. However, considering the function and responsibilities of RCs, one might expect an even higher percentage. Eighty-eight percent (15 out of 17) of the RC respondents perform some type of model testing prior to putting models on line. However, 3 of these respondents do not use live SCADA data in their testing.

Data and Information Exchange

The subsections below present the survey results for data and information exchange processes and procedures.

Processes and Procedures for Communicating Planned and Actual Internal System Transmission Grid Changes to Modeling Personnel

Table 4.2-7 summarizes the survey responses regarding "processes and procedures for communicating planned and actual internal system changes to EMS modeling personnel." The "internal system" refers to the portion of the grid for which the survey respondent has responsibility (i.e., the respondent's reliability footprint). There were a total of 41 respondents to this question, including 17 RC respondents and 24 other respondents.

Has Formal Notification Process for Internal System Changes	RC	Other	**All**
No	2	14	**16**
Yes	15	10	**25**
Totals	**17**	**24**	**41**

Table 4.2-7 — Has Formal Notification Processes for Internal Grid Changes

Sixty-one percent (25 out of 41) of the respondents, including 88 percent (15 out of 17) of the RC respondents and 42 percent (10 out of 24) of the other respondents, have documented procedures to communicate internal system changes to EMS network modeling personnel. The percentage of RCs with these procedures is significantly higher than the percentage of respondents who are not RCs. This is probably because:

- RCs typically have larger systems and thus larger models to maintain, so they need a more structured approach for learning about changes.
- Many RCs do not own some (or even any) of the transmission assets in their reliability footprint. Consequently, they are very dependent on the asset owners to provide them information on when things are changed in the field.

Table 4.2-8 summarizes the value for situational awareness that the respondents place on these procedures by those that actually have them.

Value of Internal Grid Change Notification Procedures	RC	Other	All
Essential	13	8	**21**
Desirable	1		**1**
Minimal Value	1		**1**
No Value		1	**1**
Totals	**15**	**9**	**24**

Table 4.2-8 — Value of Internal Grid Change Notification Procedures

Eighty-eight percent (21 out of 24) of the respondents that have these procedures, including 87 percent (13 out of 15) of the RC respondents and 89 percent (8 out of 9) of the other respondents, consider them "essential" for situational awareness. Only one RC respondent indicates that its procedures were of "minimal" value. Eight out of 9 of the non-RC respondents that have documented procedures stated that these procedures are "essential."

A high percentage of the RC respondents (88 percent, 15 out of 17) have procedures for communicating to EMS support staff any changes in internal grids. This is not surprising because many RCs own only a fraction of the transmission assets in their reliability footprint and are therefore dependent on the asset owners to report when changes have been made and/or when they are going to occur. All of the RCs that operate in markets have these types of procedures.

Processes and Procedures for Communicating Planned and Actual Transmission Grid Changes with External Entities

Table 4.2-9 summarizes the survey responses regarding documented "processes and procedures for communicating planned and actual system changes with external entities." The "external system" refers to that portion of the grid that is not in the respondent's reliability area of responsibility (e.g., outside the RC or TOP system footprint). There were a total of 40 respondents for this question, which included 17 RC respondents and 23 other respondents.

Formal Notification Processes and Procedures with External Entities on Planned Grid Changes	RC	Other	All
No	7	19	**26**
Yes	10	4	**14**
Totals	**17**	**23**	**40**

Table 4.2-9 — Formal Notification Processes and Procedures with External Entities for Planned Grid Changes

Table 4.2-10 indicates the value for situational awareness placed on these procedures by the respondents that have them.

Value of Formal Notification Processes and Procedures with External Entities on Planned Grid Changes	RC	Other	**All**
Essential	7	1	**8**
Desirable	3	2	**5**
Minimal Value		1	**1**
No Value		1	
Totals	**10**	**4**	**14**

Table 4.2-10 — Value of formal Notification Processes and Procedures with External Entities

From Table 4.2-10 we see that only 35 percent (14 out of 40) of the survey respondents have formal agreements and/or processes to notify and/or be notified by entities external to their reliability area regarding planned and actual changes to the physical transmission grid. This includes 59 percent (10 out of 17) of the RC respondents and 17 percent (4 out of 23) of the other respondents.

Of those that have these procedures, 57 percent (8 out of 14) of the respondents, which includes 70 percent (7 out of 10) of the RC respondents and 25 percent (1 out of 4) of the other respondents, consider them “essential.”

Maintaining a current and accurate external network model to support contingency analysis and a wide-area view would, at a minimum, appear to require processes and procedures for knowing about major changes in external transmission systems. But many of the survey respondents, including a significant number of RCs, do not have such procedures. It should be noted that the NERC DEWG has written procedures for notifying other RCs, TOPs, and similar entities about upcoming changes in the power grid. However, these procedures are neither enforced nor strictly followed. The “Planned Power System Model Change Notification Process” document can be downloaded from the DEWG section of the NERC website (http://www.nerc.com/~filez/isn.html).

Processes and Procedures for Communicating EMS-Related Changes to External Entities

Table 4.2-11 summarizes the survey responses regarding “processes and procedures for communicating planned and actual EMS-related changes with external entities.” “EMS-related changes” are changes related to EMS databases, networks, and other components that can affect entities that receive/send data from/to them. Examples of such changes are addition and/or deletions of new SCADA points, alterations related to communication links (e.g., IP address changes), changes to ICCP object IDs, etc. There were a total of 40 respondents to this question, which included 16 RC respondents and 24 other respondents.

Have Formal Notification Processes and Procedures with External Entities on Planned and Actual EMS Change Notification	RC	Other	All
No	7	18	**25**
Yes	9	6	**15**
Totals	**16**	**24**	**40**

Table 4.2-11 — Processes and Procedures for Communicating EMS-Related Changes to External Entities

Table 4.2-12 summarizes the value for situational awareness of the processes and procedures for those respondents that have them.

Value of Formal Notification Processes and Procedures with External Entities on Planned and Actual EMS Change Notification	RC	Other	All
Essential	7	2	**9**
Desirable	2	2	**4**
Minimal Value		2	**2**
No Value			
Totals	**9**	**6**	**15**

Table 4.2-12 — Value of Processes and Procedures to Communicate EMS Changes with External Entities

Table 4.2-12 indicates that 40 percent (16 out of 40) of respondents, including 56 percent (9 out of 16) of the RC respondents and 25 percent (6 out of 24) of the other respondents, have processes and procedures for notifying external entities about EMS-related changes. Of the 16 respondents that have these procedures, 87 percent (13 out of 15) consider them either “desirable” or “essential” for situational awareness. All (9 out of 9) of the RC respondents that have EMS change notification procedures state that these procedures are either “essential” or “desirable” for situational awareness. Sixty-seven percent (4 out of 6) of the other respondents that have these procedures stated that they were either “essential” or “desirable.”

It is surprising that only 9 RC respondents have these procedures because they are more likely than the other respondents to acquire real-time SCADA information from external EMS systems to support their wide-area models. However, this finding is consistent with the model information that was discussed in Section 4.1, Model Characteristics, of this report (e.g., the computed external-measurement-to-external bus ratios). However, we see from the survey responses that all 9 of the RCs who have these procedures consider them desirable or essential.

The NERC DEWG has written “*ISN Node Responsibilities and Procedures*,” which includes procedures that should be followed by entities that exchange real-time data via the ISN. Procedures include notification of server outages, software upgrades, data changes, and other related items. These procedures are not strictly enforced, however.

Agreements and Procedures for Exchanging Transmission Model Data with External Entities

Table 4.2-13 summarizes the survey responses regarding “agreements and procedures for exchanging transmission modeling data with external entities.” There were 40 respondents to these questions, which included 17 RC respondents and 23 other respondents.

Transmission modeling data include typical network model information (e.g., breaker and switch connectivity data, line and transformer parameters, generating unit parameters, etc.) in addition to supporting information such as station schematics, geographic maps, etc.

Has Formal Agreements and Procedures for Exchanging Modeling Information with External Entities	RC	Other	**All**
No	8	10	**18**
Yes	9	13	**22**
Totals	**17**	**23**	**40**

Table 4.2-13 — Agreements and Procedures for Exchanging Modeling Information with External Entities

The survey responses indicate that 55 percent (22 out of 40) of respondents, including 53 percent (9 out of 17) of the RC respondents and 57 percent (13 out of 23) of the other respondents, have agreements and procedures with external entities for exchanging modeling data.

The number of respondents with agreements and procedures for exchanging modeling information with external entities is surprisingly low, especially for the RCs. It would seem that RCs would need such procedures in place to help maintain the larger models required for their wide-area view.

Table 4.2-14 summarizes the value for situational awareness placed on data-exchange agreements with external entities by the 21 respondents that have such agreements.

Value of Formal Agreements and Procedures for Exchanging Modeling Information with External Entities	RC	Other	All
Essential	5	3	**8**
Desirable	4	4	**8**
Minimal Value		1	**1**
No Value		4	**4**
Totals	**9**	**12**	**21**

Table 4.2-14 — Value of Formal Data Exchange Agreements with External Entities

From the responses we see that 76 percent (16 out of 21) of those that have these procedures, including 100 percent (9 out of 9) of the RC respondents and 58 percent (7 out of 12) of the other respondents, think these procedures are either “essential” or “desirable” for situational awareness.

Modeling Tools and Utilities

“Modeling tools,” as defined in this report, are software applications used to build and/or maintain power system models. They include any applications supplied by vendors, provided by third parties, or created in-house. The subsections below summarize the results for the modeling tools portion of the Real-Time Tools Survey.

On-line Database Editing Capabilities

Table 4.2-15 summarizes the survey respondents’ on-line SCADA data editing capabilities. There were 43 respondents to this question, which included 17 RC respondents and 26 other respondents. Fifty-six percent (24 out of 43) of respondents, which included 65 percent (11 out of 17) of the RC respondents and 50 percent (13 out of 26) of the other respondents, have some form of on-line SCADA data editing capabilities in their EMSs.

Can you Edit existing SCADA Model Information Online?	RC	Other	All
No	6	13	**19**
Yes	11	13	**24**
Total	**17**	**26**	**43**

Table 4.2-15 — On-Line SCADA Database Editing Capability

Table 4.2-16 summarizes the value for situational awareness that respondents with on-line SCADA data editing place on this capability.

How do You Rank the Value of this On-line SCADA Editing Capability as Applied in Your Modeling Activities?	RC	Other	**All**
Essential	6	6	**12**
Desirable	4	5	**9**
Minimal Value	1	2	**3**
No Value			
Total	**11**	**13**	**24**

Table 4.2-16 — Value of On-Line SCADA Model Editing Capability

From Table 4.2-16 we see that 88 percent (21 out of 24) of the respondents that have on-line SCADA model editing capability, including 91 percent (10 out of 11) of the RC respondents and 85 percent (11 out of 13) of the other respondents, that have this capability think that it is either "desirable" or "essential" for situational awareness. Only 12 percent (3 out of 24) of respondents that have this feature, which included 1 RC and 2 other respondents, felt that this feature adds minimal value.

In general, on-line SCADA data editing capability is a feature that would only be provided by an EMS vendor as part of its proprietary database support tools. This is not a feature that one would expect to be implemented in house by EMS support personnel.

Table 4.2-17 summarizes the on-line network model data editing capabilities of the survey respondents. There were 40 respondents to this question including 16 RC respondents and 24 other respondents.

Can You Edit Network Model Database Information Online?	RC	Other	**All**
No	6	14	**20**
Yes	10	10	**20**
Total	**16**	**24**	**40**

Table 4.2-17 — On-Line Network Model Database Editing Capability

Table 4.2-17 indicates that 50 percent (20 out of 40) of the respondents, including 63 percent (10 out of 16) of the RC respondents and 42 percent (10 out of 24) of the other respondents, have on-line network model editing capabilities on their EMS. As with on-line SCADA data editing, on-line network modeling is almost exclusively a feature provided only by EMS vendors. This is not a feature that one would expect to be implemented in house by EMS support personnel.

Unfortunately, the Real-Time Tools Survey was not specific about the meaning of "on-line database editing." For instance, the survey did not differentiate among "add," "modify," and "delete" capabilities. Many EMS tools allow modification of existing data items (e.g., changing SCADA limits, line impedances or limits), but do not allow the addition or deletion of new items. Consequently, 2 survey respondents that both have on-line database editing could have answered this question in opposite ways, depending on what they interpreted it as covering.

Supplemental Model Validation Tools

Table 4.2-18 summarizes survey responses related to supplemental database validation tools. Supplemental database validation tools are applications that provide EMS database error and consistency checking above and beyond what the EMS vendor provides in its standard product. There were a total of 42 respondents to this question that included 17 RC respondents and 25 other respondents.

Supplemental Database Validation Tools	RC	Other	**All**
No	6	20	**26**
Yes	11	5	**16**
Totals	**17**	**25**	**42**

Table 4.2-18 — Supplemental Database Validation Tools

Thirty-eight percent (16 out of 42) of the respondents, including 65 percent (11 out of 17) of the RC respondents and 20 percent (5 out of 25) of the other respondents, have supplemental database validation tools. Significantly more RC respondents have these types of utilities compared to other respondents. This is probably because the RCs are generally larger organizations than other respondents and may have more support staff to develop such tools. Additionally, RCs generally have larger network models and more data to maintain.[20] Consequently, RCs have a greater need for such tools and can justify the resources required.

Network Model Merge Tools

Network model merge utilities allow users to merge a partial or full network model with an existing network model. These types of utilities are needed to facilitate activities such as replacing an existing external network model with a new one. Table 4.2-19 summarizes the survey respondents' model-merge capabilities.

Has Network Model Merge Tools	RC	Other	All
No	10	20	**30**
Yes	7	5	**12**
Totals	**17**	**25**	**42**

Table 4.2-19 — Network Model Merge Tools

There were 42 respondents to this question, including 17 RC respondents and 25 other respondents. Only 28 percent (12 out of 43) of the respondents, which

[20] RC respondents average almost twice as many buses and branches in their network models as do the other survey respondents.

include 41 percent (7 out of 17) of the RC respondents and 20 percent (5 out of 15) of the other respondents, have network model merge utilities.

The fact that 59 percent (10 out of 17) of the RC respondents do not have model merge tools suggests that there is a significant need for tools to maintain large power system models. This implies that many of the RCs are required to maintain their internal and external models more or less manually. For instance, if a new balancing authority is added to an RC's existing footprint and the RC does not have model merge utilities, it has the tedious task of manually adding the detailed model of the new balancing authority to the existing network model. This is a significant issue because many RCs and others are expanding the sizes of their internal and/or external models to enhance their wide-area views.

Network Reduction/Equivalencing Tools

Network reduction and equivalencing utilities are applications that take a given network model as input and generate a smaller reduced and/or equivalent model using network reduction algorithms and the user's specific input instructions on what power system elements to preserve, etc. This type of tool is particularly useful when building the external portion of a network model using network models from other entities (e.g., a model of the interconnection) as a starting point. Table 4.2-20 summarizes the survey responses related to these types of tools. There were a total of 42 respondents to these questions, including 17 RC respondents and 25 other respondents.

Has Network Reduction and Equivalencing Tools?	RC	Other	All
No	9	16	**25**
Yes	8	9	**17**
Totals	**17**	**25**	**42**

Table 4.2-20 — Network Reduction/Equivalencing Tools

Table 4.2-20 indicates that 40 percent (17 out of 42) of respondents, including 47 percent (8 out of 17) of the RC respondents and 36 percent (9 out of 25) of the other respondents, have network reduction/equivalencing tools.

These results suggest that 53 percent of the RC respondents and 64 percent of the other respondents do one of the following:

- use a model of the external world that is not simplified in any way
- use an external model that was generated using "engineering judgment" to determine the buses, lines, and other elements
- have a third party build an external model for them
- have no external model

The responses from the model characteristics section of the survey suggest that many of the respondents that do not have network reduction tools are relying on "engineering judgment" to select the elements to keep in their external models.

Table 4.2-21 summarizes the responses to the question for respondents that have network reduction/equivalencing tools, "Do you use these tools?"

Do You Use Network Reduction and Equivalencing Tools?	RC	Other	All
No	3	2	**5**
Yes	5	7	**12**
Totals	**8**	**9**	**17**

Table 4.2-21 — Use of Network Reduction/Equivalencing Tools by those that Have Them

Seventy-one percent (12 out of 17) of the respondents that have these tools, including 63 percent (5 out of 8) of the RC respondents and 78 percent (7 out of 9) of the other respondents, actually use them. Those that do not use them probably rely on engineering judgment when creating their external models.

CIM XML Export/Import Capabilities and Usage

Tables 4.2-22, 4.2-23, and 4.2-24 summarize the survey responses regarding CIM XML import/export capabilities and usage. There were a total of 41 respondents to this set of questions, which included 17 RC respondents and 24 other respondents (see Table 4.2.22).

Do You Have CIM XML Import/Export Capabilities?	RC	Other	All
No	8	16	**24**
Yes	9	8	**17**
Total	**17**	**24**	**41**

Table 4.2-22 — CIM XML Import/Export Capability

The responses show that 41 percent (17 of 41) of the respondents, including 53 percent (9 out of 17) of the RC respondents and 33 percent (8 out of 24) of the other respondents, have CIM import/export capability. The 17 respondents that have this capability were asked if they use it. Their responses are summarized in Table 4.2-23 below.

Do You Use Your CIM XML Import/Export capability?	RC	Other	All
No	3	4	**7**
Yes	6	4	**10**
Totals	**9**	**8**	**17**

Table 4.2-23 — Use of CIM XML Import/Export Capability by those that Have It

The response data in Table 4.2-23 shows that 59 percent (10 out of 17) of the respondents that have CIM XML import/export capability, including that 66 percent (6 out of 9) of the RC respondents and 50 percent (4 out of 8) of the other respondents, actually use it for importing and/or exporting models in CIM XML format.

Unfortunately, the survey did not specifically ask the respondents if they were using this capability for importing models, exporting models, or both. However, in Section 4.1, Model Characteristics, only 3 respondents, all of which are RCs, said they use CIM XML models as the starting point for building their external models, which would require importing CIM XML models. Conversely, this seems to imply that 7 of the 10 respondents that use their CIM XML import/export capability are using it to export models (perhaps to send to others to use?) and not to import them.

The 10 survey respondents who said they used CIM import/export capability were asked to rank the value of this capability. Table 4.2-24 summarizes the responses to this question.

How Do You Rank the Value of CIM XML File Import/Export as Applied in Your Modeling Activities?	RC	Other	All
Essential	1	3	**4**
Desirable	3	3	**6**
Minimal			
No Value			
Totals	**4**	**6**	**10**

Table 4.2-24 — Value of CIM XML Import/Export by Those that Actually Use It

From Table 4.2-24 we see that all 10 of the respondents who use CIM XML import/export capability say that it is either an "essential" or "desirable" feature as applied to their modeling activities. Only 1 of the 4 RC respondents said it was "essential," and 3 of the 6 non-RC respondents said it was "essential."

These "value" responses seem inconsistent when coupled with the fact that only 3 of the 10 respondents say that they use CIM XML imports as the starting point of their external models. (All 3 were RCs.) It may be that those that use the capability only to export models say it is essential because they are required to provide CIM XML models to others (e.g., their RCs). Or, it could be that the respondents placed a high value on this capability because CIM XML will very likely be the model exchange language of the future and they have plans to use it. Unfortunately, the survey questions related to CIM XML were not as thorough and concise as they could have been.

In an attempt to better understand the apparent inconsistencies in the survey responses, the task force contacted for follow-up questions 3 of the respondents that have used their CIM XML import/export capabilities in their modeling activities. All of those contacted were RCs who have some of the largest network models in the survey. Two of the 3 had used CIM XML models that were provided to them by other entities for major internal and external model additions and replacements, and one has just used a CIM XML model for internal model updates. Some of the interesting pieces of information that came from the follow-up questions are summarized below:

- CIM XML files have been used infrequently and only for major model additions and replacements. None of the 3 had used it for relatively small changes (e.g., incremental updates) that would be considered as "routine" model maintenance.
- It is not a "plug and play" process and generally takes weeks or months to implement changes. For instance, one respondent stated that some CIM XML files require one to two weeks to complete the import, conversion, and some basic model validation. When there is a problem with the source CIM XML file (because of data, syntax, or schema), they must request an updated version of the source model. Every request for an updated source model and the subsequent import/conversion requires two

to three weeks, so multiple requests for an updated source model can easily add three months (or more) to a project before the model reduction and model merge steps can even begin.

- Merging a CIM XML model into an existing network model is an involved process that entails both automated and manual work. The respondents have had to write special software tools to aid in their efforts.
- Some entities cannot dump their models in CIM XML output files to other entities because their EMSs do not have that capability. In that case, the receiving entities must accept files in other formats and use them to update their models.
- None of those contacted has used the CIM XML models for measurement mapping. This has done manually or by supplemental data files and tools that were created for that purpose.
- The import of the CIM XML model does not provide 100 percent of what is needed for a complete model. Custom programming and/or manual data entry is often needed to populate missing or incorrect data in the source model.

Some of the major technical issues that the respondents said they had to overcome were:

- CIM XML files do not always comply with the NERC CPSM.
- There is some room for interpretation of the CIM standard, and, as a result, certain data are not put in the data classes or attributes where another vendor would expect to find them.
- Vendor tools are not always compatible with the exact version of CIM that was used to create the source model.
- Attempts to resolve data issues by browsing XML files are nearly impossible because the files are difficult to read. Better tools are needed to review the CIM XML files for troubleshooting.
- CIM XML files are extremely large. The large file sizes stress (and sometimes break) the tools that are used to import and convert the models.

The CIM definition for power system modeling is still under development and is evolving. Most of the major EMS vendors are participating in interoperability tests to work out the existing bugs and to test new features (e.g., incremental updates). There is also an active users group that has been created to develop the CIM related standards (http://www.cimusers.org). However, despite the push in the industry to adopt and use CIM XML, the survey responses suggest that CIM XML model exchange is not yet common practice. Only 42 percent (17 out of 41) of the respondents can even export their models in CIM XML files. And only 58 percent (10 out of 17) of those that have it, and 24 percent (10 out of 41) of all survey respondents, are using it at all. Despite these challenges, the respondents that were contacted expect to be using CIM XML to a greater extent in the future as technical problems are solved and users and EMS vendors create new tools.

Recommendations for New Reliability Standards

RTBPTF makes no recommendations at this time for reliability standards related to modeling practices. However, RTBPTF recommends that additional analysis be done in several modeling areas from which recommendations for new reliability standards may be forthcoming.

Recommendation – A16

Investigate processes and procedures for internal system update and external data exchange, including CIM XML models.

Areas Requiring More Analysis

RTBPTF has identified the following areas for more analysis:

- Clarity of fundamental definitions of terms used in the existing NERC reliability standards
- Processes and procedures for grid change notification and data exchange
- Development of external system modeling guidelines
- Exchange of CIM XML models

Clarity of Fundamental Definitions

RCs and other entities have been charged with monitoring their "bulk electric systems" and having network models that provide a "wide-area view." However, existing definitions of "bulk electric system," "bulk power system," and "wide-area view" are vague and open to interpretation as evidenced by the significant variation in models reported in the Real-Time Tools Survey. An entity's interpretation of these definitions can significantly impact the size and contents of the network model it uses for its real-time applications, and, consequently, the maintenance efforts needed to keep that model current. The vagueness of these terms may partially explain some of the large differences in model sizes and characteristics that were identified in Section 4.1, Model Characteristics, (e.g., external-bus-to-total-bus ratios, etc.). NERC should clearly define these terms because their potential impact on network modeling decisions.[21] For more discussion of the need to define these terms, please see the Introduction to this report and Section 2.2, Visualization Techniques.

[21] Lack of specificity in these terms was also pointed out in the *FERC Staff Assessment*.

Recommendation – I5

Develop system models and standards for exchange of model information.

Grid Change Notification and Model Data Exchange

The power system models used to provide a wide-area view can require extensive modeling both inside and outside the reliability footprint of an RC or TOP. The external portions of the models are often more difficult to maintain than the internal portions because of the problems related to 1) knowing when something in the grid external to the reliability footprint has changed or is going to change (e.g., a new line or station is added) and 2) being able to obtain required modeling and real-time data from external entities.

As noted in the analysis above related to notification and other procedures among reliability entities, updating of external models is greatly facilitated when there are processes and procedures in place to:

- Prescribe how entities notify each other about pending grid changes far enough in the future to allow updating of real-time network models in a timely manner; and
- Identify the types of data (both real-time and modeling) that are to be exchanged, the time frames for data exchange, acceptable data exchange media and formats, required non-disclosure agreements, etc.

Many survey respondents have at least some data exchange/update processes and procedures in place with entities within their reliability footprints (i.e., their internal model areas), but few if any have such procedures in place for all of the external entities that border and/or have significant impact on their reliability footprints.

RTBPTF recommends that a task force be created to investigate grid change notification and real-time model and ICCP data-exchange processes and procedures. This task force would identify and recommend minimum standards for real-time models and data exchange similar to some of the existing "MOD" standards related to steady-state models (e.g., MOD-010, MOD-011, etc.) but more appropriate for the types of models and supplemental information required by real-time EMS applications such as the state estimator and contingency analysis. The task force should address the following:

- Grid change notification processes and procedures,
- Real-time data exchange (i.e., ICCP data) processes and procedures (a good foundation for these procedures can be found in the documents posted on the NERC DEWG website.)

- Model data exchange processes and procedures (network models and other information needed to support these models such as station schematics, regional maps, etc.), and
- Any required legal agreements needed to facilitate information exchange (non-disclosure, etc.).

External Model Development

It is evident that survey respondents have used a wide range of approaches to create external models and determine what measurements to include in them. Some external models appear to be excessively large and some excessively small, relative to the sizes of the entire models of which they are a part. Some external models contain many real-time analog and status measurements, and some have few or none.

Based on these observations, RTBPTF recommends that a task force be created to focus specifically on external models used to support real-time applications. This task force would be charged with defining guidelines and/or minimum requirements related to external modeling. The areas addressed should include, but are not be limited to:

- The level of external model detail needed to support accurate real-time contingency analysis solutions
- Methods for determining which buses, branches, and other elements to include in an external model for a given internal model
- Methods for determining the real-time analog and status measurements to be included in the external model (i.e., the level of measurement observability)
- Methods for exchanging modeling data and the data-exchange format(s) to use. This includes network model and other supporting information (e.g., station one-line diagrams)
- Methods for maintaining and updating external models
- Identification of tools needed to create and maintain an external model (CIM XML editing tools, model merge tools, reduction/equivalencing tools, etc.).

CIM XML Model Exchange

Based on the Real-time Tools Survey responses and supplemental information collected in follow-up discussions with selected respondents, it appears that some technical issues need to be resolved before the use of power system modeling data contained in CIM XML files becomes commonplace. To date, the few entities that have used CIM XML model dumps in their maintenance activities report in follow-up comments that they have found it to be a challenging exercise. Some current technical issues include:

- Problems are caused by different EMS vendor interpretations of the CIM standard.

- Vendor tools are not always compatible with the exact version of CIM used to create a source model.
- CIM XML files are generally very large. These large files sometimes stress (and sometimes break) the tools that are used to manipulate them.
- Resolving data issues by browsing XML files is difficult because these files cannot easily be read, unlike other model formats such as PSS/E, simple flat files, etc.
- Support tools to manipulate CIM models (e.g., network reduction utilities) are lacking. This is important because most users will not want to incorporate an entire model they receive from another entity (e.g., they may want to strip out the lower voltages).

Despite these and other problems, it is generally believed that CIM XML files will eventually be the preferred format for exchanging power system model data once the major technical issues are addressed.

RTBPTF recommends a review of the current state of CIM XML model exchange to determine in detail where and how this format is being used, identify known problems, and make recommendations about how the industry should proceed with CIM XML model exchange. Short-term model data exchange solutions to use in the interim should also be investigated and identified.

Recommendations for Operating Guidelines

RTBPTF does not recommend developing operating guidelines related to modeling practices and tools.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for modeling practices and tools.

Examples of Excellence

RTBPTF identified no examples of excellence related to modeling practices and tools.

Section 5.0
Support and Maintenance Tools

Introduction

RTBPTF believes that tools and applications for support and maintenance of real-time tools help enhance operator situational awareness. If real-time tools are not supported and maintained, performance measures such as application availability, data integrity, and application solution quality can be compromised without operators knowing. In addition, the equipment (i.e., servers, data links) needed to run real-time tools should be monitored and maintained to preserve the integrity and availability of the real-time tools.

Proper support and maintenance require that support and maintenance personnel have access to the tools/applications that keep real-time tools running. These are also the tools/applications that inform the operator of the availability status of essential real-time tools and thereby contribute to operator situational awareness.

RTBPTF analyzed five support and maintenance tools: display maintenance tools, change management tools and practices, facilities monitoring tools, critical applications monitoring tools, and trouble reporting tools. RTBPTF's analysis and recommendations for each of these tools are presented in Sections 5.1 through 5.5.

Section 5.1, Display Maintenance Tool — A tool/application used by support personnel to develop and maintain power system displays used by operators to monitor, assess, or perform the actions necessary to maintain the reliability of the bulk electric system. Power system displays enhance operator situational awareness.

Section 5.2, Change Management Tools and Practices — Tools/applications used by support personnel to maintain, modify, and/or test critical equipment and/or critical real-time tools[1] that operators use to monitor, assess, or perform the actions necessary to maintain the reliability of the bulk electric system. The practices and processes of support personnel are also discussed this section.

Section 5.3, Facilities Monitoring — Tool/applications that monitor the status of computer systems equipment, servers, backup systems, communications systems, networks, and other critical facilities, etc. This tool allows operators and support personnel to maintain awareness of critical equipment issues that may affect the availability of critical real-time tools used to operate and monitor the bulk electric system.

Section 5.4, Critical Applications Monitoring — Tools/applications that monitor the status of critical real-time tools. These tools allow operators and support personnel to maintain awareness of the availability status of critical real-time tools. Critical real-time tools must be available for operators to monitor, assess, and perform the necessary actions necessary to maintain the reliability of the bulk electric system.

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[1] See the Terminology subsection below for an explanation of the terms "critical equipment" and "critical real-time tools."

Section 5.5, Trouble-Reporting Tool — An application that allows control center tool users (i.e. operators and support personnel) to enter trouble reports (e.g., application problems, system problems, display problems, etc.) so that problems and their resolutions are documented and tracked.

Terminology

RTBPTF introduces two new terms in Section 5 to facilitate discussions and recommendations. The new terms are built on current definitions approved in the NERC Cyber Security Standards, CIP-002 through CIP-009, which were developed by the electric industry to improve the security of cyber assets critical to the reliable operation of the North American bulk electric system. The standards were approved by the NERC BOT on May 2, 2006, and became effective on June 1, 2006. The Cyber Security Standards define the following terms:

- Critical Assets — Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the bulk electric system.
- Cyber Assets — Programmable electronic devices and communication networks including hardware, software, and data.
- Critical Cyber Assets — Cyber assets essential to the reliable operation of critical assets.

RTBPTF introduces the following terms:

- Critical Equipment — Installed equipment that makes up the communication networks, data links, and computer equipment that are directly used as the computer infrastructure for critical real-time tools (see definition below). Critical equipment is essential for reliability entities to ensure the reliable operation of the bulk electric system. Critical equipment is a subset of critical cyber assets (i.e., not all critical cyber assets are considered critical equipment; critical equipment is critical cyber assets that are directly used as the computer infrastructure for critical real-time tools).
- Critical Real-Time Tool — Installed software that is essential (and mandatory) to support, operate, or otherwise interact with bulk electric system operations. Critical real-time tools do not include process control applications or distributed control system applications installed in generating stations, switching stations, or substations.

Significance to the August 14, 2003 Blackout

The support and maintenance tools discussed in this report address some of the issues identified by the August 14, 2003 blackout investigation. Change management tools, facilities monitoring applications, and critical applications monitoring tools enhance operator and support personnel situational awareness. Many of the recommendations for adding new requirements to the existing NERC reliability standards that are presented in the following sections of Chapter 5 relate to these three support and maintenance tools/applications.

The display maintenance tool does not directly support situational awareness; however, it is essential to the creation of power system displays, which are used by operators to enhance their situational awareness. The trouble reporting tool can be used as part of a change management tool to track and document application, system, and display problems and the resolution of each problem. Improper use of each of these tools was cited as a contributing factor to the August 14, 2003 blackout.

Processes for Interactions between Support Personnel and Operators

The lack of situational awareness caused by the failure of support personnel to have or use proper change management tools and practices played a role in the August 14, 2003 blackout. Two failures of this type were identified.

The first failure is identified in a report by the NERC Steering Group (2004):

> FE control center computer support staff did not fully test the functionality of applications, including the alarm processor, after a server failover and restore. After the FE computer support staff conducted a warm reboot of the energy management system to get the failed servers operating again, they did not conduct a sufficiently rigorous test of critical energy management system applications to determine that the alarm processor failure still existed. Full testing of all critical energy management functions after restoring the servers would have detected the alarm processor failure as early as 15:08 and would have cued the FE system operators to use an alternate means to monitor system conditions. Knowledge that the alarm processor was still failed after the server was restored would have enabled FE operators to proactively monitor system conditions, become aware of the line outages occurring on the system, and act on operational information that was received. Knowledge of the alarm processor failure would also have allowed FE operators to warn MISO and neighboring systems, assuming there was a procedure to do so, of the loss of a critical monitoring function in the FE control center computers, putting them on alert to more closely monitor conditions on the FE system.[2]

Because of this deficiency, NERC directed FE to "develop and implement a written procedure describing the interactions between control center technical support personnel and system operators. The procedure shall address notification of loss of critical functionality and testing procedures.[3]" Change management tools and practices would have aided FE in managing this type of support and maintenance issue with its critical reliability tools. A "sufficiently rigorous test" for critical equipment and critical reliability tools is necessary when changes/modifications occur to ascertain the integrity of critical infrastructure and the tools and applications used to maintain the reliability of the bulk electric system.

The second failure was when MISO support personnel analyzed the unacceptably large mismatch produced by its state estimator. The NERC Steering Group report (2004)

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[2] Technical Analysis of the August 14, 2003, Blackout: *What Happened, Why, and What Did We Learn?* 2004. Report to the NERC Board of Trustees by the NERC Steering Group. July 13. p. 96.
[3] Ibid., p. 118.

states, "... the first sign of trouble came at 12:15, when MISO's state estimator experienced an unacceptably large mismatch error between state-estimated values and measured values. The error was traced to an outage of Cinergy's Bloomington-Denois Creek 230-kV line that was not updated in MISO's state estimator. The line status was quickly corrected, but the MISO analyst forgot to reset the state estimator to run automatically every five minutes.[4]" Without proper change management tools and practices, an error such as this failure to reset a critical real-time tool and verify the integrity of the tool with operators, is more likely to occur. Errors of this type can compromise bulk electric system reliability.

As a result of the above deficiency, NERC directed MISO to "reevaluate and improve its communications protocols and procedures with operational support personnel within MISO…[5]" Change management tools and practices would have aided MISO in managing this type of support and maintenance issue with at least one of its critical reliability tools.

Section 5.1 discusses change management tools and practices, and Section 5.5 discusses trouble reporting tools, which can also be viewed as change management tools. The relationship between the two sections is the strong methodology for tying support personnel actions related to critical equipment and critical real-time tools to operator situational awareness; that is, both tools provide a means to communicate to operators any changes made to critical equipment and critical real-time tools, which enhances situational awareness.

Critical Equipment and Critical Real-Time Tools Monitoring

The ability to maintain operator situational awareness of the status of critical equipment and critical real-time tools is an essential component of reliability. NERC Steering Group analysis of the 2003 blackout (2004) states:

> …shortly after 14:14, the alarm and logging system in the FE control room failed and was not restored until after the blackout. Loss of this critical control center function was a key factor in the loss of situational awareness of system conditions by the FE operators. Unknown to the operators, the alarm application failure eventually spread to a failure of multiple energy management system servers and remote consoles, substantially degrading the capability of the operators to effectively monitor and control the FE system...[6]

The document further states that:

> … at 14:41, the primary server hosting the [FE] EMS alarm processing application failed, due either to the stalling of the alarm application, the "queuing" to the remote terminals, or some combination of the two. Following pre-programmed instructions, the alarm system application and all other EMS

[4] Technical Analysis of the August 14, 2003, Blackout: *What Happened, Why, and What Did We Learn?* 2004. Report to the NERC Board of Trustees by the NERC Steering Group. July 13. p. 28.
[5] Ibid, p. 118.
[6] Ibid, p. 27.

software running on the first server automatically transferred ("failed-over") onto the back-up server. However, because the alarm application moved intact onto the back-up while still stalled and ineffective, the back-up server failed 13 minutes later, at 14:54. Accordingly, all of the EMS applications on these two servers stopped running… The concurrent loss of two EMS servers apparently caused several new problems for the FE EMS and the system operators using it… although the FE computer support staff should have been aware that concurrent loss of its servers would mean the loss of alarm processing on the EMS, the investigation team has found no indication that the IT staff informed the control room staff either when they began work on the servers at 14:54 or when they completed the primary server restart at 15:08. At 15:42, a member of the computer support staff was told of the alarm problem by a control room operator. FE has stated to investigators that their computer support staff had been unaware before then that the alarm processing sub-system of the EMS was not working.[7]

The above excerpts illustrate the importance of operator and support personnel awareness of the availability status of critical equipment and critical real-time tools. Unavailability of critical equipment and critical real-time tools compromises the reliability of the bulk electric system. In addition, unavailability of critical equipment and critical real-time tools hinders operators' ability to maintain situational awareness.

RTBPTF Recommendations for New Reliability Standards

The NERC Cyber Security Standards address many of the issues related to critical cyber asset security that were identified by the August 14, 2003 blackout investigation. The Cyber Security Standards require that tools and processes be established to ensure that at least minimum security controls are in place to protect critical equipment. However, RTBPTF believes that the Cyber Security Standards do not sufficiently ensure operator situational awareness (i.e., RTBPTF believes that operators must be required to know the availability status of critical equipment and critical real-time tools because these tools are essential to the reliable operation of the bulk electric system).

In the sections that follow, RTBPTF makes several recommendations for modifying the requirements of NERC standard IRO-005. RTBPTF also recommends the development of three operating guidelines and identifies one area requiring additional analysis to support the recommended changes to IRO-005. In addition, the task force identifies eight entities whose use of support and maintenance tools can be considered examples of excellence within the industry.

Specifically, RTBPTF recommends that:

- Each RC and TOP be required to identify critical equipment (in a Critical Equipment Identification Document) that it uses to monitor the bulk electric system and maintain awareness of critical equipment status to ensure that

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[7] Page 33-34 of the "Technical Analysis of the August 14, 2003, Blackout: What Happened, Why, and What Did We Learn?" document

unavailability of critical equipment does not impair the reliable operation of the bulk electric system.

- Each RC and TOP be required to include, at a minimum,
    - The following list of critical real-time tools used in the operation and monitoring of the bulk electric system: alarm tools, telemetry data systems (including applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.
    - The following list of critical equipment used in the operation and monitoring of the bulk electric system: servers or computers that contain the critical real-time tools specified above and the data links that provide the input to the critical real-time tools specified above.
- Each RC and TOP be required to maintain a Critical Equipment Monitoring Document identifying its tools and procedures for monitoring critical equipment (including critical real-time applications) and notifying operators when critical equipment is unavailable.
- Each RC and TOP be required to implement automated tools or organizational processes to monitor critical equipment (which includes critical real-time applications) and related system events to ensure reliable operation of the bulk electric system.
- Each RC and TOP be required to maintain event logs pertaining to critical equipment (which includes critical real-time applications) status for a period of one year.
- Each RC and TOP be required to maintain a Critical Equipment Maintenance and Testing Document identifying its tools and procedures for maintenance, modification, and testing of critical equipment.

RTBPTF also proposes measures for the requirements recommended for Standard IRO-005-1.

Section 5.1
Display Maintenance Tool

Definition

Support personnel use the display maintenance tool to develop and maintain visual interfaces that operators use to maintain situational awareness, i.e., to monitor and assess bulk electric system reliability and/or take action to maintain system reliability.

Background

Displays are human-machine interface (HMI) views that allow operators to monitor, assess, or perform necessary actions to maintain the reliability of the bulk electric system during normal and emergency operations. Displays usually present visual representations of power system elements and other application data; this information is the basis for operator situational awareness. Although not a real-time tool, the display maintenance tool is critical for support personnel to keep visual interfaces operational.

Summary of Findings

The majority (96 percent) of respondents to the display maintenance tool section of the Real-Time Tools Survey have an operational display maintenance tool that offers the functionality defined in the survey. The overwhelming majority (94 percent) of all respondents that have an operational display maintenance tool rated it "essential" for situational awareness. Not one entity rated the application as of "minimal" or of "no value." One respondent notes that "without a display maintenance tool, there would be no way to build supporting displays." Table 5.1-1 shows the breakdown of the ratings.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, "32/38=84%" means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

Respondent Type	How do you Rate the Value of Your Display Maintenance Tool as a Critical Support Tool to Enhance Reliability Operation and Situational Awareness?	
	"Essential"	"Desirable"
All	29/31=94%	2/31=6%
RC	13/13=100%	0/0=0%
Others	16/18=89%	2/18=11%

Table 5.1-1 — Value of Display Maintenance Tool

Although respondents consistently rate the application as an essential support tool, they report significant variation in its implementation and usage.

Power System Displays

Most power system displays built for operators present SCADA measurements/telemetry data from the field. Most respondents indicate that they use power system displays that contain the state estimator or operator power-flow application solution (see Table 5.1-2). This is common industry practice: to leverage display of SCADA measurements to represent equivalent state estimator or operator power-flow solutions. Some entities use the same power system representation for their DTS application as well as their outage scheduler application. The most widely used types of power system displays are:

- One-Line Displays — visually represent a substation (transmission or distribution) and its corresponding power system elements. Discussed extensively in Section 2.2, Visualization Techniques.
- Transmission-Line Circuit Displays — visually represent the circuit connectivity of transmission substations to adjacent transmission substations; the distribution substations between two transmission substations are also often represented.
- Transmission Overview Displays — show a wide-area view of a transmission grid. Could also be referred to as dynamic overview displays or wide-area visualization displays (depending on usage). Discussed extensively in Section 2.2, Visualization Techniques.

One-Line Displays			
Type	**All**	**RC**	**Others**
SCADA	31//31=100%	12/12=100%	19/19=100%
State Estimator	27/31=87%	12/12=100%	15/19=79%
Power Flow	27/31=87%	12/12=100%	15/19=79%
DTS	17/31=55%	8/12=67%	9/19=47%
Outage Scheduler	3/31=10%	1/12=8%	2/19=10%
Transmission-Line Circuit Displays			
Type	**All**	**RC**	**Others**
SCADA	25/29=86%	10/12=83%	15/19=79%
State Estimator	26/29=90%	11/12=92%	15/19=79%
Power Flow	25/29=86%	10/12=83%	15/19=79%
DTS	14/29=48%	7/12=58%	7/19=37%
Outage Scheduler	3/29=10%	1/12=8%	2/19=10%
Transmission Overview Displays			
Type	**All**	**RC**	**Others**
SCADA	28/31=90%	11/12=92%	17/19=89%
State Estimator	22/31=71%	9/12=75%	13/19=68%
Power Flow	21/31=68%	9/12=75%	12/19=63%
DTS	14/31=45%	6/12=50%	8/19=42%
Outage Scheduler	2/31=6%	1/12=8%	1/19=5%

Table 5.1-2 — Power System Displays

Display Validation

Power system displays are critical visual representations of the monitored electric system, so the accuracy of display information is of great importance. The Real-Time Tools Survey asked respondents for a free-form description of the methods used to validate their displays. Respondents described the following methods:

- Display Testing — Displays are tested initially from a development system before being loaded into the operational system. Validation includes error checking and functional testing to ensure that displays will not harm the operational system. Links between displays and operational data are checked to be sure they are accurate and working correctly.
- Data Accuracy Checks — Despite a wide range of tools available for checking display problems, display accuracy is commonly checked manually by comparison to paper diagrams.

Noteworthy Functional Features

The survey results reveal that display maintenance tools are widely used and considered essential. The survey did not quantify their effectiveness; however, it is clear that accurate displays and detection of display errors enhance situational awareness. Many entities use multiple tools and practices to support display maintenance for various applications and systems, including wide-area overview displays and mapboards. RTBPTF believes these findings could help entities improve and benchmark their current display maintenance processes through self assessment. The following is a list of functional features deemed “essential” (based on ratings by a significant majority of survey respondents) to enhance situational awareness:

- Automatic Display Generator for Power System Displays — Enable an application to automatically generate power system displays from a single display. For example, from a SCADA station one-line display, the state estimator, power flow, etc. station one-line displays can be generated. Without this feature, support personnel would have to manually create the other power system displays. Manually creating displays could introduce errors and inconsistency; creating similar displays using a program could mitigate this problem. Forty-nine percent of respondents have an operational version of this feature. Of the entities that have this operational feature, 71 percent rate it “essential,” 14 percent as “desirable,” and 14 percent as of “minimal value” for situational awareness.
- Bad Display Link Indicator — Allows an application to automatically generate a summary of incorrect display linkages for telemetered data for multiple displays that use a given link. This feature signifies that the data being presented may be inaccurate. Forty-one percent of survey respondents have an operational version of this feature. Of the entities that have this feature operational, 92 percent rate it as “essential,” and 8 percent rate it as “desirable” for situational awareness.

Recommendations for New Reliability Standards

RCs, TOPs, and BAs depend on the availability and accuracy of displays to operate the bulk electric system in a coordinated manner so that it performs reliably under normal and abnormal conditions, as defined in NERC standards. The Real-Time Tools Survey responses reveal significant variation in display maintenance practices; the industry as a whole has no cohesive method of maintaining displays for operator use. The display maintenance tool indirectly affects bulk electric system reliability, but the availability and accuracy of the displays designed and created using this tool directly affects system reliability. These displays are discussed in Section 2.2, Visualization Techniques. RTBPTF has no recommendations for new reliability standards for the display maintenance tool.

Recommendations for Operating Guidelines

Because RTBPTF recommends no reliability standards related to display maintenance tools, it also has no recommendations for operating guidelines.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for display maintenance tools.

Examples of Excellence

RTBPTF cites the California Mexico RC's use of a display maintenance tool application to ensure that its energy management system displays are functioning properly as an example of excellence (See EOE-17 in Appendix E).

Section 5.2
Change Management Tools and Practices

Definition

Support personnel use change management tools and practices to maintain, modify, and/or test critical equipment[8] that operators use to monitor and perform necessary actions to maintain reliability of the bulk electric system.

Background

The availability and integrity of critical equipment in control centers directly affect reliability. Therefore, the tools and practices used to maintain, modify, and test critical equipment — usually called change management tools and practices – are directly related to reliability. Support personnel must use proper change management tools and practices to avoid disruptions in the function or availability of critical equipment that could affect operators' situational awareness.

The *Outage Task Force Final Blackout Report* notes that, as part of the events related to the August 2003 blackout, FE support personnel rebooted servers that had a failed alarm module without checking with control room staff/operators to confirm that all applications were running properly. In another event related to the blackout, MISO support personnel left software in a manual operation mode after solving a state estimator mismatch. These two examples signify a deficiency in change management tools and practices. On each occasion, the problem could have been averted if proper maintenance and testing procedures had been in place. In FE's case, effective change management tools and practices would have required that personnel check with the operators to find out whether the alarm tools application problem was resolved after the module reboot. In MISO's case, effective change management tools and practices would have required verification that the state estimator was running in a condition that allowed the operator to use it, so the application would not have been left in manual mode.

In short, failure of support personnel to use appropriate change management tools and practices played a role in the August 14, 2003 blackout. Causal analysis in the *Outage Task Force Final Blackout Report* reveals the following deficiencies:

> Cause 1c: FirstEnergy control center computer support staff did not fully test the functionality of applications, including the alarm processor, after a server failover and restore.

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[8] For the purposes of this discussion, *critical equipment* is defined as installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools. Critical equipment is a subset of critical cyber assets. *Critical real-time tools* are defined as installed software that is essential to support, operate, or otherwise interact with bulk electric system operations. All reliability entities (not just RCs) need critical equipment and real-time tools to ensure reliable operation of the bulk electric system.

The Corrective Actions section of the *Outage Task Force Final Blackout Report* recommends:

g. Technical Support. FirstEnergy shall develop and implement a written procedure describing the interactions between control center technical support personnel and system operators. The procedure shall address notification of testing procedures and loss of critical functionality.[9]

Summary of Findings

The Real-time Tools Best Practices Survey was designed to examine current tools and practices in software (rather than hardware) maintenance, modification, and testing. Most survey respondents (78 percent) have operational software maintenance tools. They also indicate that they have maintenance, modification, and testing practices. The majority (77 percent) of all respondents that have operational software maintenance tools rate these tools as “essential” for situational awareness; a minority (23 percent) rate their tools “desirable” for situational awareness. Not one entity rates its tools as of “minimal value” or “no value” for situational awareness. One respondent states that “it is essential for support personnel to have a quick method to access the source code of critical/core applications in case there is an issue that requires code repairs. This access needs to be controlled so that the operational environment is not affected when code is compiled and loaded into the operational system.” This majority percentage was consistent across all entity types except BAs (see Table 5.2-1).

Entity Type	How do You Rate the Value of Your Software Maintenance Tools and Practices as a Critical Support Tool to Enhance Reliability Operation and Situational Awareness?	
	“Essential”	**“Desirable”**
All	27/35=77%	8/35=23%
RCs	12/16=77%	4/16=23%
Others	15/19=79%	4/19=21%

Table 5.2-1 — Value of Software Maintenance Tools

The survey results also reveal that most entities (97 percent) that have operational software maintenance tools also have source codes on hand for their reliability tools/applications. Most entities (91 percent) indicate that their support staff can modify (when necessary) the source codes of their reliability tools/applications.

[9] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April.

Practices/Processes Related to Software Maintenance Tools

Most entities (85 percent) that have operational software maintenance tools have some form of code control process, i.e., a software (source code) change management process, such as version control, change tracking, or user management and administration. The majority of entities (81 percent) that have this process/tool available rate it "essential" for enhancing situational awareness.

Most entities (76 percent) that have operational software maintenance tools do not have the ability to notify (via paging) software support personnel if new software is loaded on-line. This question was included in the survey because RTBPTF believes this type of notification enhances situational awareness of support personnel when certain applications are being updated online.

Recommendations for New Reliability Standards

To ensure proper maintenance, modification, and testing, RTBPTF recommends that new requirements for change management tools and practices be added to existing standard IRO-005 (Reliability Coordination – Current Day Operations) to strengthen operator situational awareness. RTBPTF recommends adding the change management requirements to the reliability coordination current day operations standard rather than the cyber security standards because the latter focus primarily on protecting and securing critical cyber assets; specifically, Standard CIP-003 requires that responsible entities have minimum security management controls in place to protect critical cyber assets. The cyber security standards do not, however, explicitly address operator situational awareness of critical equipment that may affect the reliable operation of the bulk electric system.

Change management requirements could, in principle, also be added to NERC's cyber security standards CIP-002 through CIP-009, which specifically address change control and configuration management for software and hardware maintenance. Standard CIP-003 (Cyber Security – Security Management Controls), Requirement 6, states that "the Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control, and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process." The cyber security standards require that tools and processes be established so that minimum security controls are in place to protect critical equipment.

However, RTBPTF recommends adding the change management requirements to Standard IRO-005 because operator awareness of the status of critical equipment (which is directly related to critical equipment maintenance, modification, and testing processes) is essential to the RC's continuous awareness of conditions that may impair the operator's ability to operate the bulk electric system reliably. RTBPTF recommends that a new requirement be added to IRO-005 to require RCs and TOPs to implement automated tools or organizational processes to monitor critical equipment availability, including the activities related to critical equipment maintenance, modification, and testing.

RTBPTF Recommendation

The requirements recommended for addition to existing Standard IRO-005 are stated below.[10] The full text of interrelated requirements applicable to critical equipment, which comprises three areas, (change management tools and practices, facilities monitoring (Section 5.3), and critical applications monitoring (Section 5.4)) is presented here for clarity. The requirements related to the topic of this section of the report, change management tools and practices, are highlighted in italic font.

PR1. Each reliability coordinator and transmission operator shall monitor and maintain awareness of critical equipment status to ensure that the unavailability of critical equipment does not impair the reliable operation of the bulk electric system. Other entities supporting or complementing the reliability coordinator's or transmission operator's ability to operate the bulk electric system reliably shall be subject to the same requirements as the reliability coordinator or transmission operator respectively.

PR1.1. Identification of critical equipment — Each reliability coordinator and transmission operator shall identify the critical equipment it uses for bulk electric system operation and monitoring. This includes the critical equipment of parties to whom the reliability coordinator or transmission operator has delegated reliability functions. Each reliability coordinator and transmission operator shall maintain a Critical Equipment Identification Document that lists all critical equipment. The Critical Equipment Identification Document shall be kept current at all times.

PR1.1.1. Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical real-time tools used in the operation and monitoring of the bulk electric system: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.

PR1.1.2. Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical equipment used in the operation and monitoring of the bulk electric system: servers or computers that contain the critical real-time tools specified above and the data links that provide the input to the critical real-time tools specified above.

[10] Proposed requirements are designated "PR," and proposed measures are designated "PM."

Recommendation – S37

Maintain a Critical Equipment Monitoring Document to identify tools and procedures for monitoring critical equipment.

PR1.2. *Monitoring of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Monitoring Document identifying its tools and procedures for monitoring critical equipment (which includes critical real-time applications). This document shall describe how to verify that the tools and procedures are functioning and being used as intended. This document shall describe the tools and procedures for operator notification when critical equipment is unavailable*.

PR1.2.1. *Each reliability coordinator and transmission operator shall implement automated tools or organizational processes to monitor critical equipment (which includes critical real-time applications) and related system events to ensure reliable operation of the bulk electric system. These tools or organizational processes shall be described in the Critical Equipment Monitoring Document.*

Recommendation – S38

Maintain event logs pertaining to critical equipment status for a period of one year.

PR1.3. *Each reliability coordinator and transmission operator shall maintain event logs pertaining to critical equipment (which includes critical real-time applications) status for a period of one year. At a minimum, the event logs shall contain the following information regarding any event that affects the functionality and/or availability of critical equipment. The event log shall address the following questions: What happened? When did it happen? Who was notified? What was the resolution?*

Recommendation – S39

Maintain a Critical Equipment Maintenance and Testing Document identifying tools and procedures for maintenance, modification, and testing of critical equipment.

PR1.4. *Maintenance of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Maintenance and Testing Document identifying its tools and procedures for maintenance, modification, and testing of critical equipment. This document shall describe how to verify that the tools and procedures are functioning and being used as intended*.

RTBPTF recommends the following measures for the requirements stated above. The measures related to change management tools and practices are written in italic font.

PM 1. Measures for Critical Equipment Monitoring

PM 1.1 The Critical Equipment Identification Document must be available as specified in Requirement PR1.1. Additionally, each reliability coordinator and transmission operator shall demonstrate that the Critical Equipment Identification Document is kept current at all times.

PM 1.1.1. As specified in Requirement PR1.1.1, the Critical Equipment Identification Document must contain, as part of its list of critical real-time applications, the following applications: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.

PM 1.1.2. As specified in Requirement PR1.1.2, the Critical Equipment Identification Document must contain, as part of its list of critical equipment, the following equipment: servers or computers that contain the critical real-time tools, and the data links that provide the input to the critical real-time tools specified.

PM 1.2 *The Critical Equipment Monitoring Document must be available as specified in PR1.2. Additionally, each reliability coordinator and transmission operator must demonstrate that the Critical Equipment Monitoring Document is kept current at all times and that the documented tools/procedures are used as intended*.

PM 1.2.1. *Each reliability coordinator and transmission operator must demonstrate, upon request, its capability to monitor critical equipment via automated tools (e.g., critical equipment status displays or visualization tools) or organizational processes (e.g., trouble* *notification processes) as stated in Requirement PR1.2.1.*

PM 1.3 *Each reliability coordinator and transmission operator must demonstrate that the event logs as stated in Requirement PR1.3 contain the required information*.

PM 1.4 *The Critical Equipment Maintenance and Testing Document must be available as specified in PR1.4.*

Rationale

The "Purpose" section of Standard IRO-005 states, "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas." RTBPTF believes that operator awareness of the status of critical equipment (which is directly related to critical equipment maintenance, modification, and testing processes) is essential to the reliability coordinator's continuous awareness of conditions that may impair the operator's ability to operate the bulk electric system reliably. Therefore, the change management requirements for critical equipment maintenance, modification, and testing should be included as part of this standard. Other entities supporting or complementing the RC's ability to operate the bulk electric system reliably must be subject to the same requirements as the RC. As noted in the Summary of Findings section above, the *Outage Task Force Final Blackout Report* notes that the lack of strong change management tools and practices contributed to the lack of operator situational awareness related to the August 2003 blackout*.*

RTBPTF includes TOPs in the recommendations stated above because these entities are subject to the Reliability Toolbox requirement.[11]

Recommendations for Operating Guidelines

RTBPTF recommends development of the following operating guidelines for change management tools and practices. These operating guidelines support the recommended additional requirements to Standard IRO-005-1 stated above.

- Each reliability coordinator should have a demonstrated change management process for performing critical equipment maintenance, modification, and testing. This change management process should have the objective/purpose of ensuring the availability and integrity of critical equipment. The change management process should, at a minimum, include the following:
    - Management, operator, and support personnel notification and approval for production system changes
    - Pre- and post-production testing of system installation testing

[11] See the Reliability Tool Box Rationale and Recommendation section as well as the specific recommendations for each tool in the Reliability Toolbox.

    - Personnel authorization and security
    - System source code backup and recovery
- Each reliability coordinator should have a change management tool that has, at a minimum, the following capabilities:
    - Audit logging of all activities (modifications, additions, deletions, etc.) related to all source code files
    - Version control with the ability to roll back to an earlier version

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for change management tools and practices.

Examples of Excellence

RTBPTF cites PJM's use of a feature management system that provides audit logging and version control capabilities as an example of excellence (See EOE-18 in Appendix E). The approach taken by PJM ensures that software modifications do not compromise the availability and integrity of their critical real-time applications that support operator situational awareness

Section 5.3
Facilities Monitoring

Definition

The facilities monitoring application tracks the status of computer systems equipment, servers, backup systems, communications systems, networks and other critical facilities. This tool allows operators and/or support personnel to be aware of critical equipment issues that may affect the availability of critical real-time tools used to operate and monitor the bulk electric system.

Background

As discussed in detail in Section 5.0, Support and Maintenance Tools, situational awareness of the status of critical equipment, which includes facilities such as computer systems equipment, servers, backup systems, communications systems, networks and other critical facilities in the control center, is an essential component directly related to reliability. The *Outage Task Force Final Blackout Report* states that FE's operators were unaware of the failure and the concurrent loss of two EMS servers that apparently caused several new problems for the FE EMS and the operators using it. This illustrates the importance of having monitoring tools that report unavailability of critical equipment. Operators need to be aware when their ability to monitor the bulk electric system is compromised. Proper notification of maintenance and support personnel is requisite for real-time operations.

The operator has to have keen awareness of the status and availability of critical equipment. This includes critical equipment that is used as a backup to primary critical equipment. The operator could have no provision for monitoring the bulk electric system if a critical piece of equipment is unavailable or not working correctly. Critical real-time tools depend on critical equipment, and a facilities monitoring application allows for operators to be aware of the status and availability of critical equipment, which enhances operator situational awareness.

Summary of Findings

The majority of respondents (86 percent) have an operational facility monitoring application that offers the same functionality as defined in the Real-Time Tools Survey. Interestingly, all RCs report having an operational facilities monitoring application. For respondents that have an operational facilities monitor, the majority (84 percent) rate this application "essential" for situational awareness while 16 percent rate it "desirable." Not one entity rates the application as of "minimal value" or "no value" for situational awareness. One of the respondents states that "any information as to the 'state of the operational system' is a key indicator for situational awareness. For system support personnel, maintaining situational awareness of key infrastructure equipment is analogous to maintaining situational awareness of bulk power system elements." Table 5.3-1 summarizes the survey results.

Entity Type	How do You Rate the Value of Your EMS Facilities Monitor as a Critical Support Tool to Enhance Reliability Operation and Situational Awareness?	
	“Essential”	**“Desirable”**
All	32/38=84%	6/38=16%
RC	13/15=84%	2/15=16%
Others	19/23=83%	4/23=17%

Table 5.3-1 — Value of Facilities Monitor Application

These data suggest that the majority of respondents consider the facilities monitor an essential operational support tool. Because the survey results reveal a significant variation in practice, implementation, and use of this application, it is a logical candidate for some degree of standardization.

The survey asked respondents to identify the types of equipment/facilities that are monitored. A majority of respondents monitor the status of their critical servers, voice/data communication links, internal networks, and backup facilities listed (see Table 5.3-2).

Equipment	All	RC	Others
Status of Critical Servers	38/38=100%	15/15=100%	23/23=100%
Mapboard (Hardware Status) Availability	20/38=53%	11/15=73%	9/23=39%
Voice/Data Communication Links	33/38=87%	13/15=87%	20/23=87%
Internal Communication Network(s)	29/38=76%	12/15=80%	17/23=74%
RTU Status	20/38=79%	11/15=73%	9/23=39%
Availability of Backup System	33/38=87%	13/15=87%	20/23=87%
Power Supply (UPS)	26/38=68%	13/15=87%	13/23=56%
Power Supply (Backup Generators)	24/38=63%	12/15=80%	12/23=52%
Batteries	20/38=53%	10/15=67%	10/23=43%
Heating, ventilation, and air conditioning	15/38=39%	7/15=47%	8/23=35%
Fire Protection Systems	15/38=39%	7/15=47%	8/23=35%

Table 5.3-2 — Equipment/facilities Monitored Using Facilities Monitoring Application, by Entity Type

The survey reveals that entities monitor equipment that is essential to the continuing operation of their control centers. This encouraging result shows that monitoring of critical equipment is a prevailing industry practice. Awareness of critical equipment status supports situational awareness. Critical equipment monitoring tells operators what equipment is available or unavailable, which allows operators to determine whether the capability of these tools is degraded by critical equipment problems.

The survey also examined the functional features of facilities monitoring applications. Ninety-seven percent of respondents report that their facilities monitors interface directly with their alarm tools applications and can generate critical equipment status alarms. Of the entities that use this feature, 86 percent rated it “essential” for situational awareness. These data suggest that an interface between the facilities monitor and the alarm tools enhances situational awareness.

Operators at most entities (87 percent) have access to a visual representation of critical equipment status. Seventy-three percent of entities that have this feature rate it “essential” for situational awareness, 24 percent rate this feature “desirable,” and 3 percent rate it as having “minimal value.” These data suggest that a visual representation of critical equipment status enhances operator situational awareness.

Many entities (56 percent) have a system that pages support personnel when the facilities monitor indicates that a critical equipment status is unavailable. Fifty-five percent of entities that have this functional feature rate it “essential” for situational awareness, 40 percent rate it as “desirable,” and 5 percent rate it as having “minimal value.” These data suggest that an interface between the facilities monitor and a paging system enhances operator situational awareness.

Insufficient data were collected to properly evaluate the usage and implementation of the respondents’ facilities monitor applications. Ideally, to ascertain critical equipment status, the application should be independent of the equipment being monitored. Further exploration is needed to determine whether this strategy is used in the industry. More data are also needed on the methodology used to declare critical equipment “unavailable.”

Recommendations for New Reliability Standards

Because continual monitoring of the availability of critical equipment/critical real-time tools is essential for reliable power system operation, as indicated by the survey results, RTBPTF recommends adding new facilities monitoring requirements to existing standard IRO-005 (Reliability Coordination – Current Day Operations), to strengthen operator situational awareness.

Facilities monitoring requirements could, in principle, also be added to NERC’s cyber security standards CIP-002 through CIP-009, which address securing of critical cyber assets and require that tools and processes be established so that minimum security controls are in place to protect critical equipment. Specifically, Standard CIP-007, Requirement 6 mandates that the responsible entity ensure that all cyber assets within the electronic security perimeter, to the degree technically feasible, implement automated tools or organizational process controls to monitor system events related to cyber security. However, Standard CIP-007 does not explicitly address operator situational awareness of critical equipment that may affect the reliable operation of the bulk electric system; rather it focuses on automated tools or organizational process controls to monitor system events related to cyber security only. Therefore, the RTBPTF recommends adding the facilities monitoring requirements to Standard IRO-005. This standard is a more appropriate location for the requirements because the purpose of IRO-005 is operator awareness of bulk electric system parameters.

RTBPTF Recommendation

The requirements recommended for addition to existing Standard IRO-005 are stated below. The full text of interrelated requirements applicable to critical equipment, which comprises three areas, (change management tools and practices (Section 5.2), facilities monitoring, and critical applications monitoring (Section 5.4)) is presented here for clarity. The requirements related to the topic of this section of the report, facilities monitoring, are highlighted in italic font.

Recommendation – S40

Monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation.

PR1. *Each reliability coordinator and transmission operator shall monitor and maintain awareness of critical equipment status to ensure that the unavailability of critical equipment does not impair the reliable operation of the bulk electric system. Other entities supporting or complementing the reliability coordinator's or transmission operator's ability to operate the bulk electric system reliably shall be subject to the same requirements as the reliability coordinator or transmission operator respectively.*

PR1.1. *Identification of critical equipment — Each reliability coordinator and transmission operator shall identify the critical equipment it uses for bulk electric system operation and monitoring. This includes the critical equipment of parties to whom the reliability coordinator or transmission operator has delegated reliability functions. Each reliability coordinator and transmission operator shall maintain a Critical Equipment Identification Document that lists all critical equipment. The Critical Equipment Identification Document shall be kept current at all times.*

PR1.1.1. Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical real-time tools used in the operation and monitoring of the bulk electric system: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.

PR1.1.2. *Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical equipment used in the operation and monitoring of the bulk electric system: servers or computers that contain the critical real-time tools specified above and* *the data links that provide the input to the critical real-time tools specified above.*

PR1.2. *Monitoring of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Monitoring Document identifying its tools and procedures for monitoring critical equipment (which includes critical real-time applications). This document shall describe how to verify that the tools and procedures are functioning and being used as intended. This document shall describe the tools and procedures for operator notification when critical equipment is unavailable.*

PR1.2.1. Each reliability coordinator and transmission operator shall implement automated tools or organizational processes to monitor critical equipment (which includes critical real-time applications) and related system events to ensure reliable operation of the bulk electric system. These tools or organizational processes shall be described in the Critical Equipment Monitoring Document.

PR1.3. Each reliability coordinator and transmission operator shall maintain event logs pertaining to critical equipment (which includes critical real-time applications) status for a period of one year. At a minimum, the event logs shall contain the following information regarding any event that affects the functionality and/or availability of critical equipment. The event log shall address the following questions: What happened? When did it happen? Who was notified? What was the resolution?

PR1.4. Maintenance of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Maintenance and Testing Document identifying its tools and procedures for maintenance, modification, and testing of critical equipment. This document shall describe how to verify that the tools and procedures are functioning and being used as intended.

RTBPTF recommends the following measures for the requirements stated above. The measures related to change management tools and practices are written in italic font.

PM 1. *Measures for Critical Equipment Monitoring*

PM 1.1 *The Critical Equipment Identification Document must be available as specified in Requirement PR1.1. Additionally, each reliability coordinator and transmission operator shall demonstrate that the Critical Equipment Identification Document is kept current at all times.*

PM1.1.1. As specified in Requirement PR1.1.1, the Critical Equipment Identification Document must contain, as part of its list of critical real-time applications, the following applications: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.

PM1.1.2. *As specified in Requirement PR1.1.2, the Critical Equipment Identification Document must contain, as part of its list of critical equipment, the following equipment: servers or computers that contain the critical real-time tools, and the data links that provide the input to the critical real-time tools specified.*

PM 1.2 *The Critical Equipment Monitoring Document must be available as specified in PR1.2. Additionally, each reliability coordinator and transmission operator must demonstrate that the Critical Equipment Monitoring Document is kept current at all times and that the documented tools/procedures are used as intended*.

PM1.2.1. Each reliability coordinator and transmission operator must demonstrate, upon request, its capability to monitor critical equipment via automated tools (e.g., critical equipment status displays or visualization tools) or organizational processes (e.g., trouble notification processes) as stated in Requirement PR1.2.1.

PM 1.3 Each reliability coordinator and transmission operator must demonstrate that the event logs as stated in Requirement PR1.3 contain the required information.

PM 1.4 The Critical Equipment Maintenance and Testing Document must be available as specified in PR1.4.

Rationale

The “Purpose” section of Standard IRO-005 states, “The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.” RTBPTF believes that information on critical equipment status is essential to the RC’s continuous awareness of conditions that may impair the RC’s ability to operate the bulk electric system reliably. Lack of awareness that critical equipment was unavailable was a significant element contributing to the August 14, 2003 Blackout, as noted in the *Outage Task Force Final Blackout Report*. If a new requirement is not established for monitoring of critical equipment, there will be no way to ensure that operators are aware when critical equipment, such as servers, is unavailable.

RTBPTF included TOPs in the recommendation above because these entities are subject to the recommended Reliability Toolbox requirement and are required to have the critical equipment that provides the infrastructure for the Reliability Toolbox tools.[12]

Recommendation – G13

Establish a change management process for performing critical equipment maintenance, modification, and testing.

Recommendations for Operating Guidelines

RTBPTF recommends development of the following operating guidelines for the facilities monitor application. These operating guidelines support the recommended additional requirements to Standard IRO-005-1 stated above.

Recommendation – G14

Develop a notification process when critical equipment is unavailable and an analysis/resolution process for critical equipment failures.

- Each reliability coordinator should have a demonstrated critical equipment monitoring process. This monitoring process should have the objective/purpose of enhancing operator awareness of the availability of critical equipment. The monitoring process should, at a minimum, include:
    - Notification of management, operator, and support personnel when critical equipment is unavailable
    - An analysis and resolution process for critical equipment failures

[12] See the Reliability Toolbox Rationale and Recommendation section as well as the recommendations for each tool in the Reliability Toolbox.

Recommendation – G15

Develop a critical monitoring application that interfaces to alarm tools and logs all events related to the equipment failures.

- Each reliability coordinator should have a facilities monitoring application, which has, at a minimum, the following capabilities:
  - Interface of facilities monitoring application to alarm tools
  - Audit logging of all events related to critical equipment failures

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for facilities monitoring.

Examples of Excellence

RTBPTF cites American Electric Power's use of a facilities monitor application by Central and Southwest (CSWS) as an example of excellence (See EOE-19 in Appendix E). CSWS interfaces their facilities monitoring application with their critical applications monitor application.

Section 5.4
Critical Applications Monitoring

Definition

The critical applications monitor tracks the status of critical real-time tools. This application allows operators and/or support group personnel to track availability of critical real-time tools. Critical real-time tools must be available for operators to monitor, assess, and perform the necessary actions to maintain the reliability of interconnected bulk electric systems. A critical applications monitor tool may be part of a facilities monitoring tool (see Section 5.3, Facilities Monitoring).

Background

As discussed in detail in Section 5.0, Support and Maintenance Tools, situational awareness of the status and availability of critical real-time tools is an essential component directly related to reliability. The Outage Task Force Final Blackout Report stated that FE's computer support staff was unaware of the failure of their alarm tools application. FE had no alarm tools failure detection system. When the FE alarm processor stopped functioning properly, computer support staff remained unaware of this failure until a second EMS server failed approximately 40 minutes later. Because FE had no periodic diagnostics to evaluate and report the state of their alarm tools, support staff were not alerted to the eventual failure of two EMS servers or the infinite loop lockup failure of the alarms — or that the alarm processor had failed in this manner earlier and independently of the server failures. This illustrates the importance of having monitoring tools that report unavailability of critical real-time tools. Operators need to be aware when their ability to monitor the bulk electric system has degraded. Proper notification of maintenance and support personnel is requisite for real-time operations.

Summary of Findings

All respondents to the critical applications monitor portion of the Real-Time Tools Survey indicate that they have an operational critical applications monitor tool that offers the same functionality as defined in the survey. Additionally, all respondents rate their critical applications monitor as either "essential" or "desirable" for situational awareness. The majority (88 percent) rate it "essential," and not one entity rates it having "minimal value" or "no value." One respondent states that "this tool has dramatically improved… state estimator availability and…ICCP data availability." This majority rating was consistent across all entity types, as shown in Table 5.4-1.

Entity Type	How do You Rate the Value of Your EMS Critical Applications Monitor as a Critical Support Tool to Enhance Reliability Operation and Situational Awareness?	
	"Essential"	"Desirable"
All	35/40=88%	5/40=12%
RC	13/15=87%	2/15=13%
Others	22/25=88%	3/25=12%

Table 5.4-1 — Value of Critical Applications Monitor, by Entity Type

The survey results reveal that, although the majority of respondents consider the critical applications monitor tool essential, there is a significant variation in practice, implementation, and usage of the tool. Therefore, this tool is a logical candidate for standardization. The survey asked respondents to identify the types of critical applications that are monitored by their organizations. A consistent majority of respondents monitored the critical applications listed in the survey (see Table 5.4-2). Other entities also monitor automatic generation control (AGC) and market applications.

Applications	All	RC	Others
Alarm Tools	36/40=90%	12/15=80%	24/25=96%
State Estimator	28/40=70%	13/15=87%	15/25=60%
Contingency Analysis	25/40=63%	12/15=80%	13/25=52%
SCADA	37/40=93%	13/15=87%	24/25=96%
Inter-Utility Link Data Application	33/40=83%	12/15=80%	21/25=84%

Table 5.4-2 — Applications Tracked by Critical Applications Monitor, by Entity Type

The survey results indicate that the majority of entities have tools and processes to monitor applications that are critical to continuous operation of their control centers. This encouraging result shows that critical applications monitoring is a prevailing industry practice. Critical applications monitoring is important not only for computer support but also for reliable operation of the bulk electric system. Increasing operator awareness of critical real-time tool status increases situational awareness.

The survey also examines the functional features of critical applications monitor applications. All of the respondents can generate alarms based on critical real-time tools status, and the critical applications monitor interfaces directly to the alarm tools application. Of the entities that use this functional feature (interface to alarm tools), 82 percent rate it “essential” for situational awareness. These data suggest that situational awareness is enhanced if the critical applications monitor interfaces with the alarm tools application.

Operators at 72 percent of entities responding to the survey have access to visual representation of critical real-time tools status. Entities that have this functional feature rate it either “essential” (59 percent) or “desirable” (41 percent) for situational awareness. Entities that do not have this feature rate it “desirable” (73 percent) or of “minimal value” (18 percent), or “no value” (9 percent). These results indicate that a majority of the industry believes that visual representation of critical real-time tools status can enhance operator and support staff situational awareness.

Table 5.4-3 shows the percentages of respondents that have a critical applications monitor tool that can page support personnel when a critical real-time application is unavailable or stalled. Entities that have this feature rate it “essential” (56 percent), “desirable” (39 percent), or of “minimal value” (6 percent) for situational awareness. Entities that do not have this feature rate it “desirable” (40 percent), of “minimal value” (50 percent), or of “no value” (10 percent) for situational awareness. Table 5.4-3 shows that the majority of the industry has access to automatic paging from a critical applications monitor although other internal methods of notifying support personnel may be employed.

Response	All	RC	Others
Yes	20/40=50%	11/15=73%	9/25=36%
No	20/40=50%	4/15=27%	16/25=64%

Table 5.4-3 — Entities that Can Page Support Personnel When a Critical Real-time Tool is Unavailable or Stalled, as Determined by the Critical Applications Monitor Tool

The data are insufficient to evaluate the usage and implementation of survey respondents’ critical applications monitor tools. Ideally, to ascertain critical real-time tool status, the monitoring tool should be independent of the critical real-time tool being monitored. For example, if the critical applications monitor tool tracks the alarm tools application, the critical applications monitor tool and the alarm tools application should not reside on the same server. Further investigation is needed to determine whether this scheme is in use in the industry.

Recommendations for New Reliability Standards

Because continual monitoring of the availability of critical equipment/critical real-time tools is essential to for reliable power system operation, as supported by the survey results, RTBPTF recommends adding new critical applications monitoring requirements to existing standard IRO-005 (Reliability Coordination – Current Day Operations), to strengthen operator situational awareness.

Critical applications monitoring requirements could, in principle, also be added to NERC’s cyber security standards CIP-002 through CIP-009, which address securing critical cyber assets and requiring that tools and processes be established so that minimum security controls are in place to protect critical equipment. Specifically, Standard CIP-007, Requirement 6 mandates that responsible entities ensure that all cyber assets within the electronic security perimeter, to the degree technically feasible, implement automated tools or organizational process controls to monitor system events related to cyber security. However, Standard CIP-007 does not explicitly address operator awareness of critical applications that may affect the reliable operation of the bulk electric system; rather, it focuses on automated tools or organizational process controls to monitor system events related to cyber security only. Therefore, RTBPTF recommends adding the critical applications monitoring requirements to Standard IRO-005. This standard is a more appropriate location for the requirements because the purpose of IRO-005-1 is to ensure operator awareness of bulk electric system parameters.

RTBPTF Recommendations

The requirements recommended for addition to existing Standard IRO-005 are stated below. The full text of interrelated requirements applicable to critical equipment, which comprises three areas, (change management tools and practices (Section 5.2), facilities monitoring (Section 5.3), and critical applications monitoring) is presented here for clarity. The requirements related to the topic of this section of the report, critical applications monitoring, are highlighted in italic font:

PR1. *Each reliability coordinator and transmission operator shall monitor and maintain awareness of critical equipment status to ensure that the unavailability of critical equipment does not impair the reliable operation of the bulk electric system. Other entities supporting or complementing the reliability coordinator's or transmission operator's ability to operate the bulk electric system reliably shall be subject to the same requirements as the reliability coordinator or transmission operator respectively.*

PR1.1. *Identification of critical equipment — Each reliability coordinator and transmission operator shall identify the critical equipment it uses for bulk electric system operation and monitoring. This includes the critical equipment of parties to whom the reliability coordinator or transmission operator has delegated reliability functions. Each reliability coordinator and transmission operator shall maintain a Critical Equipment Identification Document that lists all critical equipment. The Critical Equipment Identification Document shall be kept current at all times.*

PR1.1.1. *Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical real-time tools used in the operation and monitoring of the bulk electric system: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.*

PR1.1.2. Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical equipment used in the operation and monitoring of the bulk electric system: servers or computers that contain the critical real-time tools specified above and the data links that provide the input to the critical real-time tools specified above.

PR1.2. *Monitoring of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Monitoring Document identifying its tools and procedures for monitoring critical equipment (which includes critical real-time applications). This document shall describe how to verify that the tools and procedures are functioning and being used as intended. This document shall describe the tools and procedures for operator notification when critical equipment is unavailable.*

PR1.2.1. Each reliability coordinator and transmission operator shall implement automated tools or organizational processes to monitor critical equipment (which includes critical real-time applications) and related system events to ensure reliable operation of the bulk electric system. These tools or organizational processes shall be described in the Critical Equipment Monitoring Document.

PR1.3. Each reliability coordinator and transmission operator shall maintain event logs pertaining to critical equipment (which includes critical real-time applications) status for a period of one year. At a minimum, the event logs shall contain the following information regarding any event that affects the functionality and/or availability of critical equipment. The event log shall address the following questions: What happened? When did it happen? Who was notified? What was the resolution?

PR1.4. Maintenance of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Maintenance and Testing Document identifying its tools and procedures for maintenance, modification, and testing of critical equipment. This document shall describe how to verify that the tools and procedures are functioning and being used as intended.

RTBPTF recommends the following measures for the requirements stated above. The measures related to change management tools and practices are written in italic font.

PM 1. *Measures for Critical Equipment Monitoring*

PM 1.1 *The Critical Equipment Identification Document must be available as specified in Requirement PR1.1. Additionally, each* *reliability coordinator and transmission operator shall demonstrate that the Critical Equipment Identification Document is kept current at all times.*

PM1.1.1. *As specified in Requirement PR1.1.1, the Critical Equipment Identification Document must contain, as part of its list of critical real-time applications, the following applications: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.*

PM1.1.2. As specified in Requirement PR1.1.2, the Critical Equipment Identification Document must contain, as part of its list of critical equipment, the following equipment: servers or computers that contain the critical real-time tools, and the data links that provide the input to the critical real-time tools specified.

PM 1.2 *The Critical Equipment Monitoring Document must be available as specified in PR1.2. Additionally, each reliability coordinator and transmission operator must demonstrate that the Critical Equipment Monitoring Document is kept current at all times and that the documented tools/procedures are used as intended*.

PM1.2.1. Each reliability coordinator and transmission operator must demonstrate, upon request, its capability to monitor critical equipment via automated tools (e.g., critical equipment status displays or visualization tools) or organizational processes (e.g., trouble notification processes) as stated in Requirement PR1.2.1.

PM 1.3 Each reliability coordinator and transmission operator must demonstrate that the event logs as stated in Requirement PR1.3 contain the required information.

PM 1.4 The Critical Equipment Maintenance and Testing Document must be available as specified in PR1.4.

Rationale

The “Purpose” section of Standard IRO-005 states, “The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.” RTBPTF believes that information on critical applications’ status is essential to the RC’s continuous awareness of conditions that may impair its ability to operate the bulk electric system reliably. Lack of awareness that critical real-time tools (e.g., FE’s alarm processor application) were unavailable significantly contributed to lack of operator situational awareness in the August 14, 2003 blackout, as noted in the *Outage Task Force Final Blackout Report.*

If a new requirement is not established for monitoring of critical real-time tools, operators may be unaware when these tools (such alarm tools or contingency analysis applications) are unavailable, which could impair their ability to monitor interconnected bulk electric system reliably.

RTBPTF includes TOPs in the recommendations stated above because these entities are subject to the Reliability Toolbox requirement and are required to have the critical equipment that provide the infrastructure for these tools.[13]

Recommendation – G16

Develop a process for monitoring critical real-time tools including change notification, status update, and severity of a situation.

Recommendations for Operating Guidelines

The survey results show that critical applications monitors are widely used by all types of entities in the industry. Although the survey did not quantify the tool's effectiveness, it is clear that awareness of the availability and status of critical real-time tools increases operators' situational awareness, which is essential for reliability monitoring as required by existing NERC standards. Because of the prevalence of critical applications monitor use, the following recommended operating guidelines appear feasible.

RTBPTF recommends development of the following operating guidelines for the critical applications monitor application. These guidelines support the recommended additions to Standard IRO-005-1 described above.

- Each reliability coordinator should have a demonstrated process for monitoring critical real-time tools. This monitoring process should have the objective/purpose of enhancing operator awareness of the availability of critical real-time tools. The monitoring process should, at a minimum, include the following:
    - Notification of management, operators, and support personnel when critical real-time tool are unavailable
    - Analysis and resolution process for critical real-time tool failures

[13] See the Reliability Toolbox Rationale and Recommendation section as well as the recommendations for each tool in the Reliability Toolbox.

- Critical real-time tool status should, at a minimum, be one of the following: (a) available — running, (b) available — stalled, or (c) unavailable. For example, if the critical real-time tool is functioning correctly (i.e., the output data are updating), the application would be deemed AVAILABLE — RUNNING. If for some reason, the application process/task is still alive but the output data from the application are not updating (because of internal application problems/issues), the application would be deemed AVAILABLE — STALLED. If the application/process is dead or non-existent (e.g., the application failed because of a core dump), the application would be deemed UNAVAILABLE.
    - If possible, the critical applications monitor should specify the severity of the situation, i.e., indicate the action to take to return the tool to AVAILABLE — RUNNING status. "High severity" would mean that a total system reboot is necessary to correct the UNAVAILABLE state.

Recommendation – A17

Investigate whether critical application monitor tools should be independent of the critical real-time tool being monitored.

Areas Requiring Additional Analysis

Ideally, in order to ascertain critical real-time tool status, the critical applications monitor tool should be independent of the critical real-time tool being monitored. For example, if the critical applications monitor tool monitors the alarm tools application, the critical applications monitor tool and the alarm tools application should not reside on the same server. Further investigation is needed to determine the prevalence of the use of this scheme throughout the industry.

Examples of Excellence

RTBPTF cites Tennessee Valley Authority's use of a critical applications monitoring tool that monitors all critical and non-critical processes on their SCADA system as an example of excellence (See EOE-20 in Appendix E).

RTBPTF cites International Transmission Company's use of a critical applications monitoring tool that that monitors the status of their state estimator and ICCP data applications as an example of excellence (See EOE-21 in Appendix E).

RTBPTF cites American Transmission Company's use of overview displays that not only show system performance but also EMS health checks as an example of excellence (See EOE-22 in Appendix E). These overview displays allow the system operator to determine whether the EMS is operational and functioning properly.

RTBPTF cites Central and Southwest's use EMS Facilities Monitoring application with its critical applications monitor as an example of excellence (See EOE-23 in Appendix E).

Section 5.5
Trouble-Reporting Tool

Definition

A trouble-reporting tool allows control center tools/applications users (operators and support personnel) to document problems (e.g., application, system, and display difficulties and malfunctions) and resolutions.

Background

RCs, TOPs, and BAs depend on real-time tools to operate the bulk electric system in a coordinated manner and ensure reliable operations under normal and abnormal conditions, as defined in the NERC standards. A trouble-reporting tool allows users to document problems related to critical real-time tools and may also be used to improve existing support processes.

Support processes help ensure the viability of systems and applications that underpin reliability functions in a control center. These processes allow operators to manage control center infrastructure, which evolves as a result of regular technology changes. Computer system outages and lack of infrastructure stability often result from lack of effective support processes, increasing the risk that critical equipment and real-time tools, used by operators to monitor, assess, or perform the actions necessary to maintain the reliability of the bulk electric system, will not be available. As part of support processes, trouble-reporting tools improve computer operations and help control and keep track of trouble report status (e.g., current computer system issues and their estimated time of repair) that may affect operators' situational awareness.

Summary of Findings

Most respondents (67 percent) to the trouble-reporting tool section of the Real-Time Tools Survey have an operational trouble reporting tool. RCs are most likely to use trouble-reporting tools; 94 percent of RCs responding to the survey have these tools. Table 5.5-1 summarizes the survey results.

Entity Type	Percentage of Entities That Have Operational Trouble Reporting Tools
All	31/46=70%
RC	16/17=94%
Others	15/29=52%

Table 5.5-1 — Entities with Operational Trouble-Reporting Tools

Most respondents that have an operational trouble reporting tool rate it "essential" (61 percent) or "desirable" (35 percent) for situational awareness. A minority of respondents (3 percent) rate their trouble-reporting tool as having “no value.” One respondent that rates the tool “essential” states that “the Trouble Reporting Tool is used for having an indication of the usage of the EMS Production Support Resources. Additionally, special application incidents, incident reports, and Software Incident Reports are generated and tracked.” “Essential” ratings varied across entity types (see Table 5.5-2) although RCs were most likely (88 percent) to assign this rating.

Entity Type	How do You Rate the Value of Your Trouble Reporting Tool as a Critical Support Tool to Enhance Reliability Operation and Situational Awareness?		
	“Essential”	“Desirable”	“No value”
All	19/31=61%	11/31=35%	1/31=3%
RC	14/16=88%	2/16=13%	0/16=0%
Others	5/15=33%	9/15=60%	1/15=7%

Table 5.5-2 — Value of Trouble Reporting, by Entity Type

The survey results also show that for most entities (93 percent), the trouble-reporting tool is a stand-alone application that is not integrated into EMSs. No tool features emerged as predominant among entity types. The following features were addressed in the survey:

- Display Attachments — This function allows users to attach displays or bitmap images to a trouble report. This feature allows users to efficiently describe a problem by attaching a display or bitmap image of it. (Forty-seven percent indicate that they have this feature, and 27 percent indicate that this feature is “essential” for situational awareness).
- Summary Reports — This function allows users to generate summaries (e.g., trouble reports by functional area) for analysis of trends. (Fifty-nine percent indicate that they have this feature, and 36 percent indicate that it is “essential” for situational awareness).
- Direct User Feedback — This function allows the application to indicate who originates a trouble report and the current status of the report. (Sixty-two percent indicate that they have this feature, and 28 percent indicate that this feature is “essential” for situational awareness).

Recommendations for New Reliability Standards

RTBPTF does not recommend any new reliability standards requiring use of a trouble-reporting tool. RTBPTF believes that the recommendations in Section 5.2, Change Management Tools and Practices, are sufficient to support operator situational awareness related to critical equipment and critical real-time tool maintenance, modification, and testing processes. RTBPTF believes that the trouble-reporting tool is useful and could be integrated with support processes required by the standards recommended in Section 5.2. The trouble-reporting tool could be used formally to document support processes.

Recommendations for Operating Guidelines

The survey results show that trouble-reporting tools are not as prevalent among industry entities as other tools despite the perceived value of trouble-reporting tools for enhancing support processes. The survey results did not quantify the effectiveness of the trouble-reporting tool, but it appears clear that having a tool to track problems and resolutions related to critical equipment and critical real-time tools will enhance situational awareness for both support personnel and operators. However, because change management processes vary in the industry, RTBPTF does not recommend development of new operating guidelines for trouble-reporting tools at this time. Operating guidelines recommended in Section 5.2 are sufficient.

Areas Requiring Additional Analysis

RTBPTF identified no areas requiring additional analysis for trouble-reporting tools.

Examples of Excellence

RTBPTF cites Florida Power and Light's (FPL) Trouble Report System, which facilitates logging, communication, and tracking of user problems with tools and systems maintained by the computer support group at FPL's System Control Center as an example of excellence (See EOE-24 in Appendix E). In addition to allowing entries of new trouble reports, the application performs administrative functions and can produce different query-based summary reports.

Section 6.0
Next Steps

NERC and the industry have much work to do to implement the RTBPTF recommendations described in this report for revised standards and operating guidelines to improve electric system reliability through better real-time operating tools and practices. In addition, NERC and the industry have much to do to conduct the necessary additional analyses of issues for which the task force could not provide specific, technically defensible recommendations or that were outside task force's scope.

To initiate the next steps in the process, RTBPTF proposes to finish work on the specific activities discussed below, which will complete the remainder of the task force's scope of work as assigned by the NERC Operating Committee (OC). Following completion of these activities, RTBPTF will disband.

RTBPTF's recommendations are intended to inform the standards development process. With assistance from NERC staff, RTBPTF will append its recommendations for revised standards to the existing Standards Review Forms that are included in the NERC Standards Development Plan: 2007–2009.[14] The relevant recommendations will be added to the "To Do List" section of the form for each affected standard along with other issues already identified from various sources such as the *FERC Staff assessment* of the NERC standards and comments on the standards from various industry stakeholders. As the standards development plan proceeds, RTBPTF will provide technical support to the standards drafting teams that will author the necessary revisions in accordance with the NERC Reliability Standards Development Procedure.[15]

RTBPTF will also prioritize the areas that the task force identified as requiring more analysis. For areas that the task force believes must be addressed by a new team of experts, RTBPTF will offer to write high-level scopes of work in the form of bullet points that the new teams should consider in drafting their own charters. RTBPTF will deliver the prioritized list of areas needing additional analysis to the NERC ORS and will prepare scope-of-work bullet points as requested by the ORS.

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[14] FERC_Filing_Volumes_I-II-III_Reliability_Standards_Development_Plan_30Nov06.pdf on www.nerc.com
[15] http://www.nerc.com/standards/newstandardsprocess.html

Recommendation – I6

Provide adequate funding and staffing for maintaining and upgrading real-time tools.

RTBPTF also recommends that others take two important additional steps that are outside the scope that the OC assigned to the task force. First, the task force recommends that the OC direct the ORS to determine how operating guidelines are to be developed and maintained. Consistent with the work already done by the ORS in this area, RTBPTF suggests that ORS consider asking the regional reliability organizations (RROs) to develop operating guidelines as “supplements” to NERC standards. Second, the task force urges NERC to develop a plan to address each of the “six major issues” identified by RTBPTF and described in the Introduction to this report.

RTBPTF does not take a position on the disposition of the Examples of Excellence listed in Appendix E of this report. They are presented for consideration by NERC and the industry, with the disclaimers noted in Appendix E.

Glossary of Terms Used in this Report

The following are definitions of terms used throughout this report. The report also contains terms as defined in the "Reliability Standards for the Bulk Electric Systems of North America" document.[1]

Term	Definition
Alarm tools	Applications that emit real-time visible and audible signals to alert operators to events and conditions affecting the state of the bulk electric system. Alarm tools can be external, embedded within the SCADA/EMS system, or a combination of both.
Automatic safety bet	Visualization tool that provides the tools/displays for operators to monitor, initiate, or disable triggering of schemes that shed firm load for under voltage or under frequency conditions. Automatic safety net could work with a remedial action scheme monitor.
Outage Task Force Final Blackout Report	U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April.
Bulk Electric System Elements List	A term developed by RTBPTF to refer to a list of specific bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) within an RC area. The Bulk Electric System Elements List shall contain the necessary bulk electric system elements (within the RC area) so that potential or actual SOL/IROL violations could be identified.
Change management tools	Tools and practices used by support personnel to maintain, modify, and/or test critical equipment that operators use to monitor and perform necessary actions to maintain reliability of the bulk electric system.
Commercial/industrial demand-side management	See "Commercial/industrial load management"
Commercial/industrial load management	Tools that enable operators to curtail commercial/industrial electric demand. This type of tool is similar to residential load or demand-side management but is applied to commercial/industrial customers. A typical application of this type of tool is the disconnection of the electric supply feed from the supplying entity through direct computer control by operators to reduce electric demand.
Congestion management application	Application used for relieving network congestion within an entity's service territory using operational means that lie within the entity's control authority, e.g., generation redispatch, curtailment of transactions within the entity's service area, capacitor bank switching, opening low voltage lines, etc. Typically, it may be a security-constrained dispatch program, an optimal power-flow program, or a heuristic program that searches for the best solution from a set of options. For an ISO or an RTO, this may be part of the LMP application.

[1] For these terms, please refer to the Glossary in the latest official copy of the NERC Reliability Standards, which can be found at http://www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html.

Term	Definition
Contingency analysis	Computer application used to analyze the impact of specific, simulated outages (lines, generators, or other equipment) or higher load, flow, or generation levels on the security of the system. Contingency analysis identifies problems such as line overloads or voltage violations that will occur if a new event (contingency) happens on the system. The state estimator solution is a representation of current system conditions and usually serves as the base case in the analysis. The information a contingency analysis generates enables RCs and TOPs to implement mitigation plans in advance of a contingent event such as a line trip. Contingency analysis is used as a real-time application as well as for studying potential scenarios.
Critical applications monitoring	Tracks the status of critical real-time tools. This application allows operators and/or support group personnel to track availability of critical real-time tools. Critical real-time tools must be available for operators to monitor, assess, and perform the necessary actions to maintain the reliability of interconnected bulk electric systems. A critical applications monitor tool may be part of a facilities monitor tool.
Critical equipment	Installed equipment that makes up the infrastructure and systems (including communication networks, data links, hardware, application software, and databases) that are directly used as the computer infrastructure for critical real-time tools. Critical equipment is essential for all reliability entities to ensure the reliable operation of the bulk electric system. Critical equipment is a subset of critical cyber assets.
Critical facility loading assessment	Application that evaluates a set of contingencies and calculates the post-contingency loading of a set of monitored facilities using telemetered SCADA flows and LODFs. CFLA may be used as a backup application if the state estimator and/or contingency analysis applications fail.
Critical real-time tool	Installed software that is essential to support, operate, or otherwise interact with bulk electric system operations. Critical real-time tools do not include process control applications, distributed control system applications installed in generating stations, switching stations, or substations.
Display maintenance tool	Tool used by support personnel to develop and maintain visual interfaces that operators use to maintain situational awareness, i.e., to monitor and assess bulk electric system reliability and/or take action to maintain system reliability.
Dynamic mapboard	Physical collection of painted lines, status lights, and analog readouts presenting, in a stationary prominent location, continuous real-time status of important selected components of the power system to operators. It is “dynamic” because the statuses of important selected components of the power system are updated in real time. A dynamic mapboard usually complements common SCADA/EMS displays.

Term	Definition
Dynamic overview display	One-line and other graphical displays depicting the state, loading, and/or voltage levels over the wider area (or a sub-area within the entity's internal footprint) of the power system. Dynamic overview displays are essentially large SCADA one-line displays. Examples of this type of visualization tool are area overview one-line displays, which are one-line displays that show a group of electrically connected substations for a specified area.
Dynamic stability assessment	Application (or a suite of applications) executing in near-real time that aid in determination of system operating limits based on transient dynamic stability assessment using a current state estimator model of the real-time system. A dynamic stability assessment may also provide an indication of the dynamic stability margin for the most critical fault/contingency condition.
Emergency tools	Applications or procedures that operators use when the power system enters or is about to enter an emergency. The NERC Glossary defines "emergency" as "[a]ny abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System."
Facilities monitor	Tracks the status of computer systems equipment, servers, backup systems, communications systems, networks and other critical facilities. This tool allows operators and/or support personnel to be aware of critical equipment issues that may affect the availability of critical real-time tools used to operate and monitor the bulk electric system.
Flowgate monitor	Visualization tool that provides the tools/displays for operators to monitor actual and contingency flows on designated flowgates. The NERC Glossary defines "flowgate" as "[a] designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions." This type of visualization tool provides flowgate information to operators; it could run either within or independent of SCADA/EMS systems.
Inter-control center communications protocol	Inter-Control Center Communications Protocol (ICCP) is a standard data exchange protocol that is widely used in the electric utility industry to communicate information between operating entities. The NERC ISN utilizes ICCP to support data exchange among RCs, and several intra-regional and intra-company networks also use this protocol to support the provision of data to RCs from operating entities within the RC area.
Inter-regional real-time coordination for market redispatch	Application used to adjust the market dispatch within the entity's service territory in coordination with adjacent RCs to manage the inter-regional congestion problem in real-time. This tool may be handled by the entity's congestion management application, or it may be handled through a different process.

Term	Definition
Inter-regional voltage profile coordination	Application that coordinates the voltage profiles between two or more regions. This application may contain features such as wide-area voltage contour visualization, voltage schedule coordination between regions, etc.
Line outage distribution factor	Estimation of impact from an outage over a facility can be done using LODF. In general, an outage impacts the system by transferring the amount of power flowing on the outaged elements during pre-contingency conditions to other facilities in the system. These changes could increase or decrease power flow on the facilities depending on network topology, load, and generation dispatch. LODF is formulated as a percentage of pre-contingency flow on the outaged line that appears on the monitoring facility during contingency conditions.[2]
Load reduction by voltage reduction	Enables the operator to curtail electricity demand by reducing the distribution-level voltages. This scheme usually involves direct computer control (via SCADA systems) to automatic voltage regulating relays on LTC power transformers and step voltage regulators. By means of the control of the dry contact closure to the regulating relay, its regulating center band voltage is reduced to a lower level by boosting the sensed voltage of the voltage regulating relay. This causes a reduction of the distribution voltage schedule, which reduces electricity demand for a short period.
Locational marginal pricing	A market-pricing approach used to manage the efficient use of the transmission system when congestion occurs on the interconnected bulk electric system.
Network topology processor	SCADA-based application that determines facility status and station configuration based on breaker and switch status data. The processor converts a nodal network model into a bus-branch model, for use by other applications such as the state estimator. It may perform the same function for study network applications such as power flow.
Offline power flow	See “Power Flow”
Online power flow	See “Power Flow”
Operator	System operator
Power flow	Application used to calculate the state of the power system (flows, voltages, and angles) by using available input data for load, generation, net interchange, and facility status. Power flow is divided into two categories: “online power flow” and “offline power flow.” An “online power flow” application is typically integrated within an EMS (or has a direct data feed from an EMS) and utilizes node-breaker topology whereas “offline power flow” is based on bus-branch models and static data. Power flow is widely used in real-time systems to assess system conditions or perform look-ahead analysis. Power flow is also used to study “n-1” contingencies and to identify potential future voltage collapse or reliability problems.

[2] Source: http://www.caiso.com/docs/2005/05/03/200505031714217356.pdf.

Term	Definition
Reactive reserve monitor	Visualization tool that allows operators to monitor reactive reserves (from static and dynamic sources) in local geographic areas or major load centers. This visualization tool can alarm the operator when a generating unit has reached its reactive capability or an area has approached the minimum reactive reserve requirement. This type of visualization tool could also be the real-time user interface representation of the documented set of procedures, practices, or guidelines for maintaining awareness of the current and near-term reactive reserve capability.
Real-Time Tools Best Practices Task Force	The task force responsible for this report
Real-time contingency analysis	See "contingency analysis"
Remedial action scheme monitor	Visualization tool that provides the tools/displays for operators to monitor the status of critical power system parameters and measure the proximity of these parameters to the triggering conditions for special protection schemes or total system failure. This tool alarms and advises operators of actions required to mitigate the pending power system condition.
Residential demand-side management	See "residential load management"
Residential load management	Enables the operator to curtail residential electric demand for specific appliances. Residential load or demand-side management (DSM) consists of planning, implementing, and monitoring activities designed to encourage residential consumers to modify their level and pattern of electricity usage. These activities are also designed to shape electricity demand through direct computer control of specific appliances. For example, when necessary, operators could turn off air conditioners of residential customers that sign up for a residential DSM program.
Rotating load shed	Enables the operator to curtail load by initiating or scheduling load shedding. The *Outage Task Force Final Blackout Report* defines "load shedding" as "… the process of deliberately removing (either manually or automatically) pre-selected customer demand from a power system in response to an abnormal condition, to maintain the integrity of the system and minimize overall customer outages." For this type of tool, rotating load shed refers only to manual load shedding scheduled or initiated by operators via computer control.
SCADA one-line display	Dynamic, one-line diagram displays of substations and major power system components that present the real-time status and selected flow, voltage, and other data of the power system. This is the most common type of visualization tool used today to monitor bulk electric system elements or parameters.
Security-constrained dispatch	See "congestion management application"
Selectable data trending	Visualization tool that provides the ability to plot graphically selected power system values, using up-to-date data on the plot at a reasonable refresh rate on real-time displays used by operators and others. Displays are used by system operators and others.

Term	Definition
Short-term load forecasting	Application that predicts short-term (next 0-60 minutes) loads based on parameters such as short-term weather effects, current load, etc. The result from this tool could be used for predictive redispatch, look-ahead contingency analysis, awareness of scheduled non-conforming load changes, etc.
Short-term weather forecasting	Application that predicts short-term (next 0-60 minutes) extreme weather that may impact operations, e.g., a lightning prediction tool, Doppler radar, etc.
Short-term wind energy forecasting	Near real-time application that is used to predict and manage generation in response to the variability of supply from wind-energy sources.
Short-term hydro scheduling	Real-time application used to manage deviations from the long-term optimized schedule (for hydro units) for reasons of reliability, e.g., a response to a DCS event, acquiring support for localized voltage control, etc.
State estimator	Application that performs statistical analysis using a set of imperfect, redundant, telemetered power system data to determine the system's current condition. The system condition or state is a function of several variables: bus voltages, relative phase angles, and tap changing transformer positions. A state estimator can typically identify bad analog telemetry, estimate non-telemetered flows and voltages, and determine actual voltage and thermal violations in observable areas. The state estimator application has two main uses. It provides (1) a base case for reliability-analysis applications, and (2) input to other system monitoring tools. The state estimator solution is typically used as the base case for other reliability-related applications, such as contingency analysis. In some cases, the state estimator is used primarily as the basis for information communicated to operators regarding power system status, e.g., the state estimator drives the alarm application that alerts operators to power system events.
State estimator one-line display	Dynamic, one-line diagram displays of substations and major system components that present the state estimator solution for status and selected flow, voltage, and other data from the power system.
Study area one-line display	Study area one-line displays are one-line diagram displays of substations and major system components that present the active study context of status and selected flow, voltage, and other data from the power system model in use. Examples of this type of visualization tool are power flow one-line displays, contingency analysis one-line displays (for a specified contingency), etc.
Study real-time maintenance	Application that simulates real-time network applications (e.g., NTP, state estimator, contingency analysis, etc.) and debugs problems without affecting the operation of the real-time applications. Can be an on-line application integrated with the production EMS system, an application integrated with a non-production EMS system (i.e., DTS, etc.), or an off-line application.

Term	Definition
Telemetry data	Status and analog values originating from conventional SCADA/EMS or equivalent systems (telemetry data systems) and are updated continuously in real-time or near-real-time operation. These data may come directly from SCADA system(s) or from direct connection (ICCP, ISN, etc.) to SCADA systems operated by others.
Telemetry data systems	Tools or applications that process and provide telemetry data. SCADA is an example of a telemetry data system.
Topology and analog error detection	Application that identifies and/or automatically overrides incorrect SCADA breaker and switch statuses to enhance a NTP and to improve the accuracy and robustness of the state estimator. May also identify and/or automatically ignore SCADA analog measurements that are unreasonable or inconsistent with network connectivity.
Transaction impact monitor	Type of visualization tool that provides the tools/displays for operators to monitor scheduled transactions and interchange flows between balancing authorities.
Trouble-reporting tool	Allows control center tools/applications users (operators and support personnel) to document problems (e.g., application, system, and display difficulties and malfunctions) and resolutions.
Visualization tools/techniques	A group of user interface applications, tools, or displays that provide concise visual monitoring and enhanced multiple views of relevant power system data in real time to operators and others. Visualization tools help operators monitor and better understand system events and/or conditions across neighboring power systems that may be affecting reliable operations in their part of the power system.
Voltage stability analysis	Application executing in near-real time that aids in determination of system operating limits based on voltage stability assessment using a current state estimator model of the real-time system. VSA may derive minimum voltages at key buses below which voltage collapse may occur under further stress to the system, evaluate whether sufficient stability margins exist for an analyzed base case, provide margins relative to particular stress modes such as transfers or system loading, or provide information on minimum dynamic reactive reserves required in local areas.
Wide-area view boundary	The NERC glossary defines “wide area” as “[t]he entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.” RTBPTF defines “wide-area view boundary” as the network model boundary for the “wide area.” For reliability coordinators, the “wide-area view boundary” defines the minimum required network model in order to support the monitoring requirements for the “wide area.” This network model should contain all the bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) bounded by the wide area view boundary.

Term	Definition
Wide-area visualization tools	Displays/tools driven by SCADA, EMS, PMU, disturbance recorder, and other technical data collected in real time that present concise information for the "wide area." In general, these displays/tools show multiple views of the status of critical facilities within the entity's internal footprint, but they are also used to show views of critical facilities or data from the entity's external footprint that have the potential for adverse impact to the internal system (the "wide area" as defined in the NERC Glossary). By this definition, dynamic overview displays may also be considered wide-area visualization tools. Besides the traditional SCADA/EMS displays that show critical reliability parameters, wide-area visualization tools use other forms of technology/methodology to present vast amounts of information in a form such that the operator can assess the state of the system in an intuitive and quick manner.

Appendix A
Real-Time Tools Survey Development and Software

Introduction

RTBPTF's scope includes the assignment to "develop a focused survey (preferably web-based) for distribution to entities responsible for reliable operations to determine which tools those entities use to perform state estimation, perform real-time contingency analysis, and maintain situational awareness of their systems." To fulfill this assignment, the task force developed the Real-Time Tools Survey and delivered it as an interactive, on-line, web-based questionnaire. Lawrence Berkeley National Laboratory provided programming, database, and systems integration services for the survey. This Appendix summarizes the survey's development and briefly describes the software system that was created to support it, including its testing, quality assurance, and role in the survey analysis.

Summary of Survey Development

The survey in its final form was more than 300 pages long, with nearly 2,000 questions organized into five major sections: Real-Time Reliability Tools, Situational Awareness Practices, Real-Time Data Acquisition and Exchange, Modeling Practices, and Support and Maintenance Practices related to the real-time tools.

Real-Time Tools

The initial basis for the selection of the real-time tools investigated in the survey was a report on minimum requirements and best practices for reliability software, presented at a July, 2004 FERC technical conference on Information Technology for Reliability and Markets, (Docket No. PL04-12-000).[1] Starting from the applications addressed in that presentation, RTBPTF narrowed the list to real-time operator tools. (The task force did not consider long-term, medium-term, day-ahead, training, or market or economic operations tools.) Based on their collective expertise and experience, the task force members then developed a complete list of reliability tools that directly support situational awareness and formulated definitions for each tool. Special emphasis was placed on tools to aid operator situational awareness because the *Outage Task Force Final Blackout Report* repeatedly points to lack of operator situational awareness as a key cause of the August 14, 2003 blackout. The real-time tools portion of the survey was designed to elicit, from different types of entities responsible for reliable

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[1] Macedo, Frank. Consultant to FERC. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

operation of the bulk electric system, descriptions of their use of each tool. The task force's goal was to characterize, based on the survey results, each tool's industry-wide status.

Situational Awareness Practices

The task force reviewed the then-current NERC reliability standards to identify elements of situational awareness that were addressed to some extent in the standards. These elements formed the basis for survey questions on operating practices, processes, and procedures used to maintain situational awareness.

Data, Modeling, and Support and Maintenance Tools

The three remaining sections of the survey address the acquisition and exchange of real-time data needed to support real-time reliability tools and practices, the characteristics of the real-time models needed to support those tools (as well as the practices used to build and maintain the models), and other tools and practices to support and maintain real-time reliability tools. These topics were included in the survey because real-time reliability tools require accurate input data, well-designed models, and effective maintenance to produce meaningful results that operators can depend on for situational awareness.

Survey Structure

Task force members extensively debated the optimal structure for the individual questions in the survey. Some members felt that asking general questions that required a detailed, free-format written response would elicit the most comprehensive and insightful information and thus the best basis for identifying candidates for follow-up questioning. The downside to this structure would have been the enormous challenge of analyzing the responses, especially for a questionnaire of this length.

Some task force members favored an alternative structure with sets of specific questions on a particular subject, each having yes/no or multiple-choice answers, designed to elicit, in the aggregate, a complete picture of a topic but requiring minimal effort from respondents. The upside of this approach is that the responses could be easily queried, sorted, and analyzed statistically. The downside is that respondents could not elaborate on their answers.

The final decision was to use a yes/no, multiple-choice structure but to give respondents the ability to add free-format written comments on key topics addressed in the questions.

Each section of the survey described above was broken into individual subsections that addressed specific tools or practices. Within each subsection, the questions were designed and arranged to: identify the types of entities using the tool or practice; inventory the functions of the tool or practice; and rate the value of the tool, function, or practice for situational awareness. In addition, survey respondents were asked to identify what they perceive as *best practices* in their control centers for the particular tool or practice.

The task force finished designing the survey in April 2005 and sent it to Lawrence Berkeley National Laboratory for programming. Beta testing began in June 2005, and the survey was rolled out to reliability coordinators (RCs), transmission operators (TOPs), and balancing authorities (BAs) in August 2005. The task force closed the survey in November 2005 and began analyzing the results in preparation for this final report. The task force presented an overview of its preliminary findings and recommendations to the NERC Operating Reliability Subcommittee (ORS) in November 2006.

Survey Hardware and Software

The RTBPTF on-line survey has two internal components: a web server, and a database, as illustrated in Figure A-1. A secure web server, maintained by NERC staff in Princeton NJ, hosted the survey software. The database stored the questionnaire structure and all of the users' responses. The software generated the web pages through which respondents navigated to read the questions and insert answers by reading directly from the design data (e.g., section, question number, question text, question type) stored in the questionnaire portion of the database. Figure A-2 shows examples of the user interface web pages. All communication between users and the questionnaire took place over an encrypted channel to ensure the security of users' responses. The software used to produce the web site and control the database is written in PHP (www.php.net), which interacts with a MySQL (www.mysql.com) database.

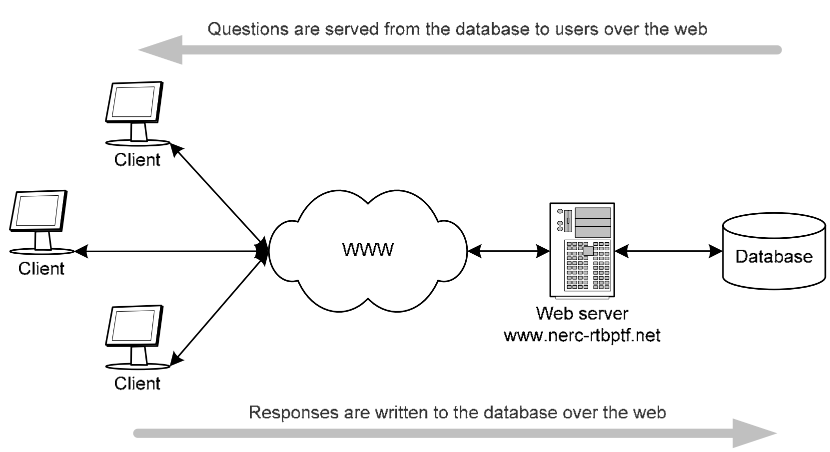

Figure A-1 — Software Communication

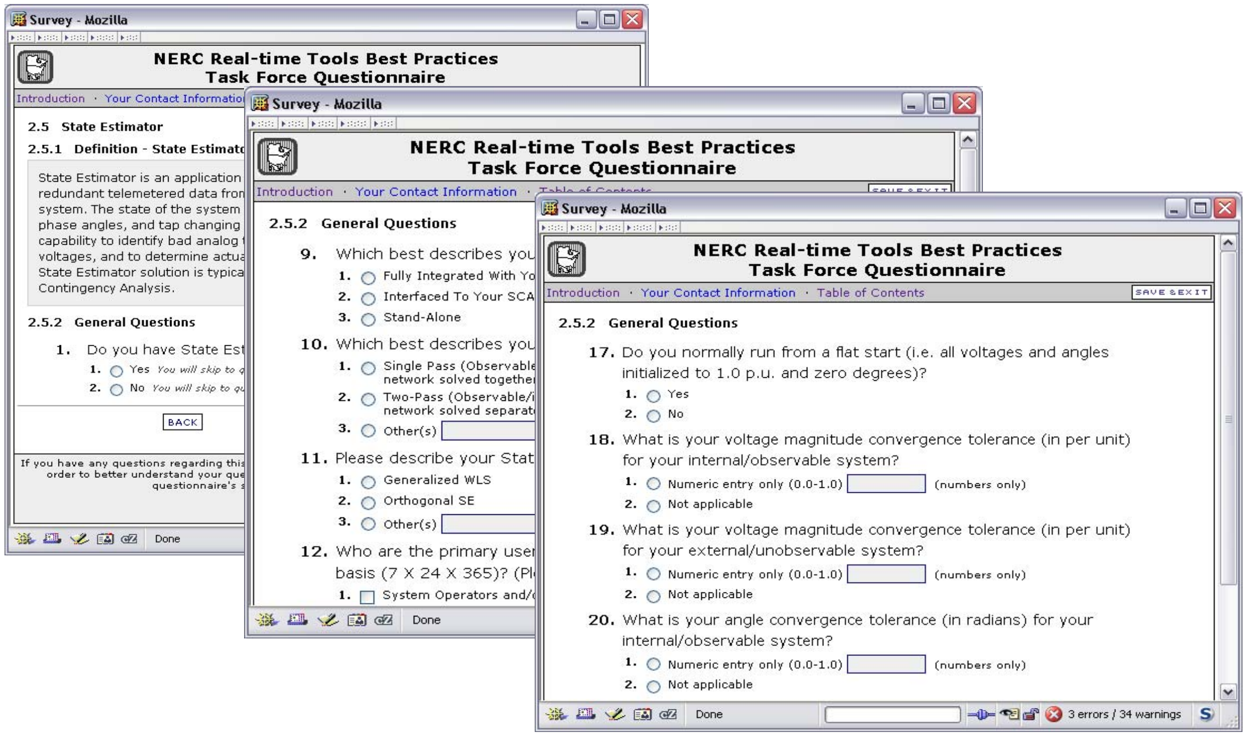

Figure A-2 — User Interface Web Page Examples

Testing

To ensure ease of use and confirm the accuracy of the software application, task force members tested it rigorously prior to release for both completeness and functionality (e.g., navigation among and within survey sections). Improvements in questionnaire content entailed adding or editing database records to add or edit questions. Improvements in questionnaire functionality (e.g., to aid navigation by respondents) entailed direct modifications to the interface software.

Quality Assurance

After the survey period ended, additional software tools were developed that were tailored to task force needs, to interrogate the database and assess consistency among and completeness of user responses. In a few cases, individual users were contacted to clarify conflicting responses.

Interfaces were built on the web server with the following functionalities:

- View survey completion counts by reliability region,
- Download aggregate results of all answers in spreadsheet format,
- View user profiles and download their surveys by reliability region, and
- View aggregate responses for individual questions.

Results/Deliverables

Final output from the questionnaire database was provided in two formats: 1) a report of aggregate responses for each survey question (which can be downloaded as pdfs at: http://www.nerc.com/~filez/rtbptf.html), and 2) the entire questionnaire database in Microsoft Access format.

The report of aggregate responses summarize all responses for each survey question. Responses are presented first aggregated for all respondents, followed by an aggregation of responses received from reliability coordinators.

To mask individual respondents' identities, all comments entered in free-format text fields were globally post-processed to remove references to a specific entity name. These references were replaced with a generic label or term, depending on the context.

The Microsoft Access database containing the raw survey responses is an abridged version of the master MySQL database. Data in the MySQL database specific to the functioning of the web site were not ported to the abridged version. Only data specific to the questions, answers, and respondents were included. The members of the task force received the abridged version to support their individual interrogation and analysis of the questionnaire responses. Figure A-3 shows the database schema.

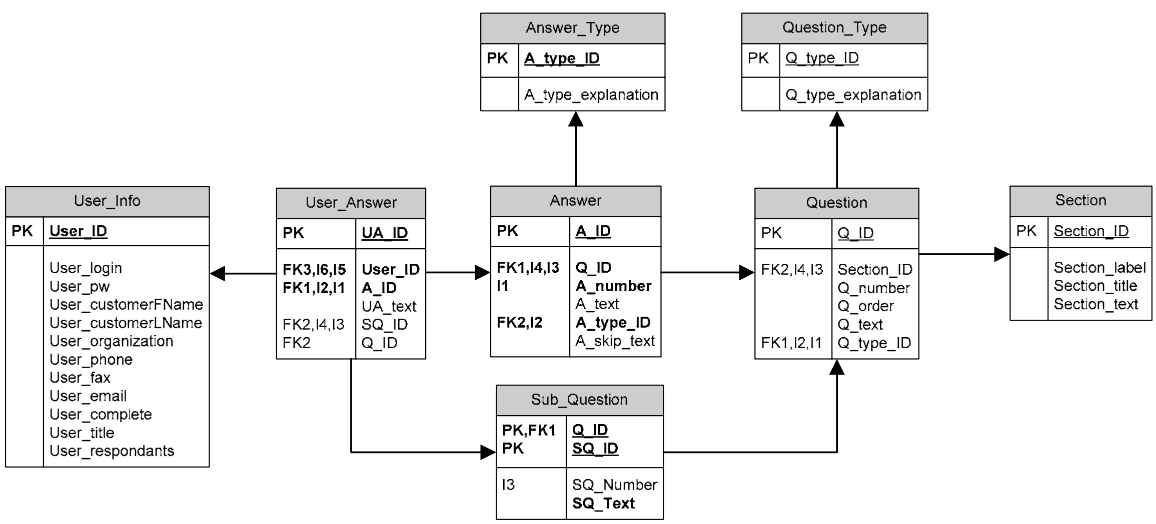

Figure A-3 — RTBPTF Questionnaire Database Schema

Appendix B
Survey Participation

The Real-Time Tools Survey was designed to collect information from NERC registered RCs, TOPs, BAs, and other interested (but unregistered) operating entities who use real-time tools to monitor or analyze the reliability of the bulk electric system. RTBPTF invited representatives from each entity listed in the NERC Transmission System Information Network (TSIN) database to participate in the survey. A total of 59 entities (registered and unregistered) requested access to the survey and completed at least one section. Entities that did not complete at least one section were excluded from the analysis. The survey participants included all 17 North American RCs, 39 TOPs, and 3 BAs (who are not also TOPs or RCs).

Several entities that completed the survey perform more than one NERC function. For example, some entities may serve as both a TOP and a BA; others [e.g., the Electric Reliability Council of Texas] may even serve as RC, TOP, <u>and</u> BA. RTBPTF contacted these "multi-function" entities to clarify their status, and each was reclassified, for purposes of the survey, according to its highest-level function. RCs are considered the highest-level entities, and balancing authorities are considered the lowest-level entities, with TOPs in the middle. Thus, for example, an entity registered as a TOP and an RC would be classified as an RC for the survey analysis; an entity registered as a BA and a TOP would be classified as a TOP. This classification protocol was used to ensure that the information submitted by each participant was not counted more than once in the final analysis of survey results.

Some entities' situations posed classification challenges. One RC contracts some or all of its real-time reliability tools through a registered TOP. The survey response submitted by the TOP for this entity included the RC's response. Therefore, after contacting both entities, the task force reclassified the TOP's response as an RC response. One entity that responded to the survey was not a NERC registered RC, TOP, or BA. After the task force contacted this entity, its response was classified in the category that most closely corresponded to its role.

The entities that participated in the survey are listed below according to the function assigned to each for survey analysis purposes. Figure B-1 shows a map of the geographical footprint of RCs that participated in the survey, and Table B-1 lists the RCs. Figure B-2 shows the footprint of the TOPs and BAs that participated in the survey, and Tables B-2 and B-3, respectively, list the TOPs and BAs.

Reliability Coordinators	
1	Bonneville Power Administration (BPAT) for Pacific Northwest Security Coordinator
2	Southern Company Services, Inc. (SOCO) for Southern Subregion
3	Entergy Services, Inc. (EES)
4	Energy Reliability Council of Texas Independent System Operator (ERCOT)
5	Florida Reliability Coordinating Council (FPL / FRCC)
6	Hydro-Quebec TransEnergie (HQT)
7	The Independent Electricity System Operator (IMO)
8	Independent System Operator New England (ISNE)
9	New Brunswick System Operator (NBSO)
10	New York Independent System Operator (NYIS)
11	Pennsylvania-New Jersey-Maryland Interconnection (PJM)
12	Duke Energy Corporation (DUK) for VACAR-South
13	California Mexico Reliability Coordinator (CMRC)
14	Midwest Independent System Operator (MISO)
15	Rocky Mountain - Desert Southwest Reliability Coordinator (RDRC)
16	Southwest Power Pool (SWPP)
17	Tennessee Valley Authority (TVA)

Table B-1 — Entities who participated in the Real-time Tools Survey and were classified as RCs

Transmission Operators	
1	Alabama Electric Cooperative, Inc. (AEC)
2	Alberta Electric System Operator (AESO)
3	American Electric Power (AEP) - Central & Southwest (CSWS)
4	Associated Electric Cooperative, Inc. (AECI)
5	Cinergy Corp (CG&E)
6	Cinergy Corp (PSI)
7	Cleco Corporation (CLEC)
8	COMISION FEDERAL DE ELECTRICIDAD (CFE)
9	First Energy (FE)
10	Idaho Power Company
11	International Transmission Company (ITC)
12	Lincoln Electric System (LES)
13	Northern Indiana Public Service Co. (NIPS)
14	NorthWestern Energy (NWMT)
15	Oklahoma Gas & Electric (OKGE)
16	Otter Tail Power Company (OTP)
17	Public Service Company of New Mexico (PNM)
18	Grant County Public Utility District (GCPD)
19	Public Utilities District # 1 of Douglas County (DOPD)
20	Santee Cooper (SC)
21	Saskatchewan (SPC)
22	Sierra Pacific Power Company (SPPC)
23	South Carolina Electric & Gas Company (SCEG)
24	Southern Minnesota Municipal Power Agency (SMP)
25	Southwestern Public Service - Xcel (SPS)
26	Tennessee Valley Authority (TVA)
27	Vectren Energy Delivery of Indiana (VEDI)
28	Westar (WR)
29	Western Area Power Administration - Upper Great Plains Region (WAUW)
30	Allegheny Power (AP)
31	American Electric Power (AEP)
32	American Transmission (ATC)
33	Aquila Inc. (WPEL)
34	City Utilities, Springfield MO (SPRM)
35	Dominion Virginia Power
36	HydroOne
37	Lansing Board of Water & Light
38	National Grid – NY / Niagara Mohawk Power Corporation (NMPC)
39	Rochester Public Utilities (RPU)

Table B-2 — Entities who participated in the Real-Time Tools Survey and were classified as TOPs

Balancing Authorities	
1	City of Tallahassee (TAL)
2	Madison Gas and Electric Company (MGE)
3	We Energies / Wisconsin Energy Corporation (WEC)

Table B-3 — Entities who participated in the Real-Time Tools Survey and were classified as BAs

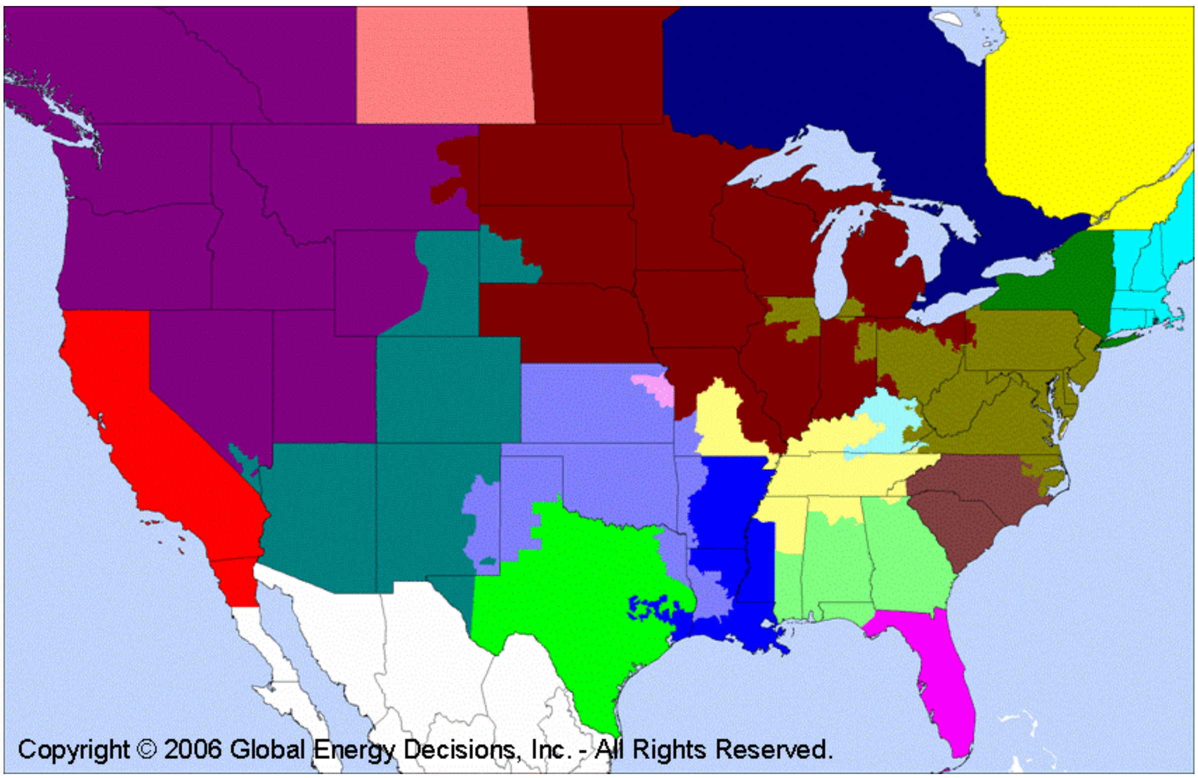

Figure B-1 — Footprint of RCs that participated in the Real-Time Tools Survey

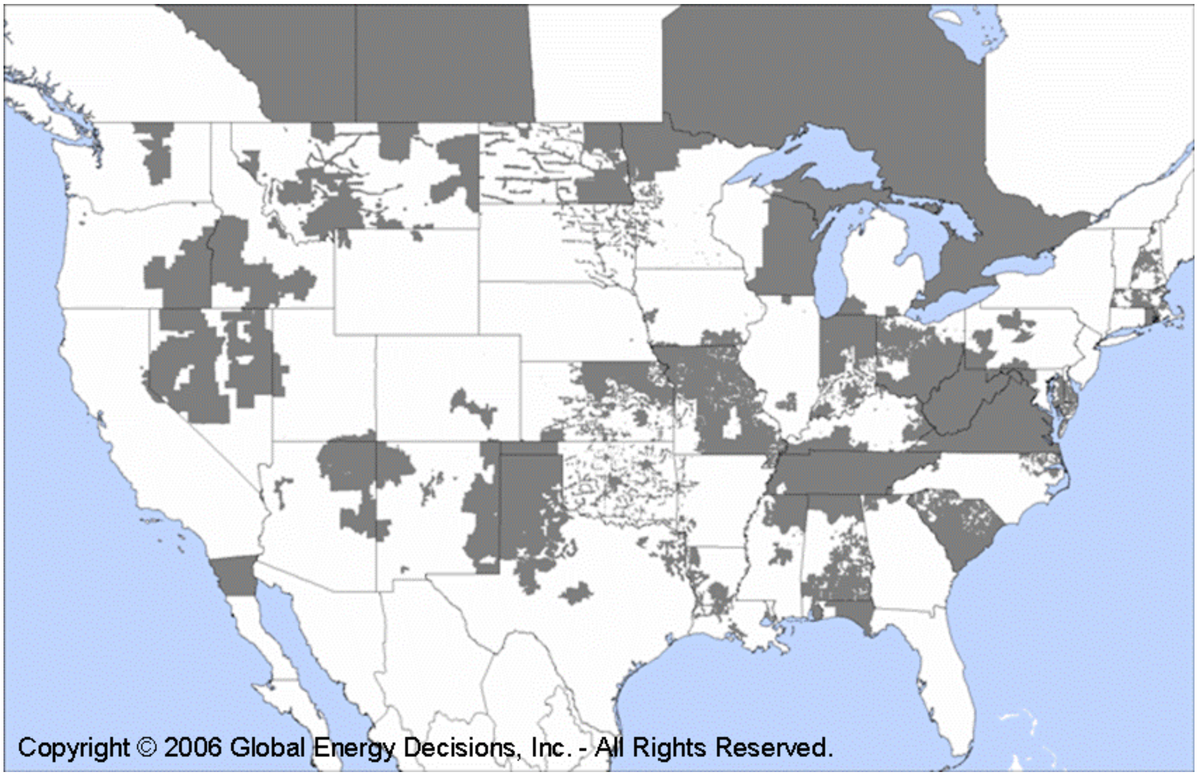

Figure B-2 — Footprint of TOPs and BAs (that are not also RCs) that participated in the Real-Time Tools Survey

Appendix C
Survey Analysis Methodology

Introduction

Given the breadth and depth of the Real-Time Tools Survey, RTBPTF recognized that reviewing and analyzing the survey responses would be a monumental task. This appendix explains the methodology that the task force developed to summarize and analyze the survey results and to develop recommendations from them.

Individual task force members reviewed and analyzed specific survey sections and prepared the corresponding portions of this report. To process the massive number of data from the survey, the task force used summary reports and database query tools. To ensure consistency and uniformity of individual reviewers' efforts and to produce this final, comprehensive report, the task force created and followed a structured methodology and a checklist of key steps.

The sections below describe the tools; checklist; and underlying criteria, principles, and guidelines that the task force used in analyzing the survey data.

Analysis Tools

RTBPTF members accessed the database of all survey responses on a secure web site hosted by NERC. Lawrence Berkeley National Laboratory (LBNL), which created the survey software, also created summary reports of responses organized by survey section. These reports were posted on the secure web site, so task force members could download them. In addition, LBNL created an on-line tool that enabled task force members to query the responses to any individual question and see a breakdown by respondent type – RC, TOP, and/or BA.

Task force members could also download the entire survey database and create their own custom queries and reports. One task force member created a summary report of the entire database in a text format and shared it with the other members. Other members created and shared database queries, indices, spreadsheets, and tables.

Survey Review Checklist

The task force created a checklist that outlined the "roadmap" for the complex journey from raw survey responses to the material needed to prepare a final report that would fulfill the task force's deliverables requirement. The checklist contained the following steps:

- Download and review the results file for each task force member's assigned section

- Use Question Query Tool to review responses to particular questions by entity type
- Download survey database into Microsoft Access and design custom queries as needed
- Prepare initial, high-level lists of findings
- Identify related questions from other sections to validate/invalidate initial findings
- Review initial findings in relation to the report on minimum requirements and best practices for reliability software presented at 2004 FERC technical conference on Information Technology for Reliability and Markets[2]
- Refine and summarize initial findings
- Develop recommendations for new standards based on summary of findings
- Develop recommendations for operating guidelines based on summary of findings
- Identify areas requiring more analysis based on summary of findings
- Identify examples of excellence based on survey responses and follow-up interviews

Principles for Summarizing Findings

To ensure that they did not stray from RTBPTF's scope, the task force members focused, when summarizing the survey findings, primarily on issues directly related to reliability and situational awareness. Thus, they undertook to address causes of the August 14, 2003 blackout that were related to real-time tools and situational awareness, as identified in the NERC Steering Group Report to BOT[3] and the *Outage Task Force Final Blackout Report*.[4] In addition, RTBPTF members reviewed existing reliability standards to identify the ones containing requirements related to the tools or practices covered in the survey and to determine which standards needed new or revised requirements. After FERC

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[2] Macedo, Frank. Consultant to FERC. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14.
http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps
P

[3] NERC Steering Group. 2004. *Technical Analysis of the August 14, 2003, Blackout: What Happened, Why, and What Did We Learn?* Report to the NERC Board of Trustees. July 13.

[4] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April.

issued its *Staff Assessment* of NERC's proposed reliability standards,[5] RTBPTF endeavored to address the issues raised in the assessment that were germane to the task force's scope.

In summarizing survey findings, the task force differentiated between the responses of RCs and those of other survey participants where possible and relevant. One reason for breaking out RC responses was to highlight any major differences between the reliability tool use and operating practices of RCs and those of other entities. Another reason was that all 17 RCs responded to the survey, so, in statistical terms, the total population of RCs was represented. However, only about one-third of registered TOPs and BAs (who are not also RCs) participated, so those responses represent non-random samples of the populations of TOPs and BAs.

RTBPTF looked for clear majorities in the responses to questions about tool usage and practices to identify prevalent practices, which help form the rationale for many of the recommendations in this report. The tables and statistics in the technical sections of this report are designed to illustrate how many respondents answered specific questions in particular ways. In writing their analyses, task force members attempted to summarize the conclusion supported by each set of statistics and tables.

Other guiding principles for summarizing survey results included: 1) quoting survey respondents' comments when quotes are appropriate and help make a point, 2) not self-censoring findings and recommendations because of anticipated controversies, 3) identifying areas in which most respondents seem to be doing well, 4) identifying areas where the industry in general needs improvement, and 5) identifying important issues where the data are insufficient to properly evaluate a tool or practice or are too inconclusive to justify action.

Criteria for RTBPTF Recommendations

RTBPTF's recommendations in this report are based upon several criteria that the task force established to determine which of the following four options were justified by the survey findings for each topic: 1) recommendation for new reliability standards (or revisions to existing standards), 2) recommendation for operating guidelines, 3) identification of areas requiring more analysis, or 4) identification of examples of excellence. These four options were derived from the task force's understanding of its assigned responsibilities as explained in the discussion of "best practices" in the Introduction to this report. The specific criteria for each option are described below.

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[5] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

Basis for Recommending New or Revised Reliability Standards

1. Recommendations for revisions to existing standards must support or provide clarification to the existing standards.
2. Recommendations for new reliability standards must pertain to tools or practices that materially affect bulk electric system reliability.
3. Recommended requirements must be measurable.
4. All recommendations must support the NERC Reliability and Market Interface Principles.[6]
5. Recommendations must be made by consensus of RTBPTF's active members.
6. Recommendations should support the needs and gaps identified by the NERC and Outage Task Force *Blackout Reports* and the FERC *Staff Assessment* of NERC standards.

Basis for Recommending Operating Guidelines

RTBPTF's criteria for recommending operating guidelines are based to some extent on the criteria for establishing "Best Practices" identified by the NERC Operating Committee's Best Practices Task Force in its report,[7] which was approved by the NERC Operating Committee in December 2005. A key recommendation of the Best Practices Task Force was that "Operating Guidelines" and "Examples of Excellence" should be established in lieu of "Best Practices." RTBPTF's criteria for recommending practices to be documented as operating guidelines are as follows:

1. Practice must be prevalent within the industry (employed by >50 percent of survey respondents).
2. Practice must support an existing or proposed standard.
3. Practice must be proven to be effective.
4. Practice cannot be considered to be essential to maintaining bulk electric system reliability (because operating guidelines are not mandatory).
5. Practice must be feasible to implement.
6. Practice must be applicable over a wide range of organizations that perform the practice for which the operating guideline applies.

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[6] ftp://ftp.nerc.com/pub/sys/all_updl/tsc/stf/ReliabilityandMarketInterfacePrinciples.pdf
[7] *Best Practices Task Force Report: Discussions, Conclusions, and Recommendations*. 2005. December 1.

Basis for Identifying Areas Requiring More Analysis

1. Were the survey results inconclusive?
2. Was the tool or practice not adequately addressed in the survey?
3. Is the topic a significant “hole” in the overall reliability “fabric?”

Basis for Identifying an Example of Excellence

Because the Real-Time Tools Survey was completed prior to the Best Practices Task Force final report mentioned above, which recommended that "Operating Guidelines" and “Examples of Excellence" be established in lieu of "Best Practices," the survey results included “Best Practices” that were self-nominated by survey respondents. RTBPTF reviewed the nominations and attempted to identify the practices related to tools and/or operating practices that go beyond the minimum requirements of existing standards and are unique to individual organizations but may not be applicable throughout the industry.

The criteria used to differentiate the self-nominated practices and develop the examples listed in this section of the report are as follows:

1. Example must be nominated by either the individual entity or a task force member, and must be approved by both.
2. Example can be assumed to function as stated, i.e., task force will not verify functionality.
3. Recommendations that do not demonstrate an understanding of the tool or a practice discussed in the report will not be considered.
4. Example must be an existing practice, not a desired or planned practice for which empirical results have not been established.
5. Example must be considered not to be commonly used by the majority of the industry; however, the task force will not conduct a side-by-side comparison of each respondent’s practices.
6. Example must be an outstanding practice that the industry could strive to achieve.
7. From survey responses, the task force identified self-nominated “best practices.”
8. Identified best practices were correlated with examples of excellence from NERC readiness audits.

In lieu of conducting face-to-face interviews with the respondents who self-nominated an example of excellence, the task force conducted follow-up email surveys with those respondents. The follow-up surveys consisted of the following questions:

1. Have User fully describe the tool/practice:
    a. What does it do?

    b. Who uses it?
    c. What are the inputs/outputs?
    d. What is the user interface?
    e. What is/was the alternative practice?
2. How does it enhance reliability and/or situational awareness?
3. Which reliability standard(s) does it help meet or exceed?
4. What did it take to implement?
5. What does it take to maintain?

Appendix D
Real-Time Tools Survey

The RTBPTF Real-Time Tools Survey questionnaire and the survey results are available at http://www.nerc.com/~filez/rtbptf.html.

Appendix E
Examples of Excellence

Introduction

Real-Time Tools Survey participants were given an opportunity to document a potential example of excellence. RTBPTF reviewed each proposed example of excellence and in some instances requested additional information before deciding to include it in this report. Appendix E presents all the examples of excellence that RTBPTF recommends to the industry for further consideration.

A detailed description of each example of excellence follows, with cross reference to the section of the report in which the example is identified.

Examples of Excellence

EOE-1

Reference — Section 1.1, Telemetry Data

Submitted by — Northeast Power Coordinating Council (NPCC)

Description

RTBPTF has recommended modifications to existing NERC reliability standards with regard to monitoring of bulk electric system elements/parameters. Section 1.1, Telemetry Data, addresses the need to clarify the definition of the term “bulk electric system.” RTBPTF recommends that RCs produce a document called the Bulk Electric System Elements List to specify the elements/parameters monitored within a reliability area. RTBPTF cites the Northeast Power Coordinating Council (NPCC) as an example of excellence in establishing and facilitating a process/methodology for classifying bulk power system elements within the NPCC RRO. NPCC’s “Criteria for Classification of Bulk Power System Elements (A-10)” document (http://www.npcc.org/document/abc.cfm) is used to identify elements to which NPCC bulk power system criteria apply. NPCC’s A-10 Criteria document recognizes that each RC area has an existing list of bulk power system elements.

RTBPTF believes that NPCC’s methodology for classifying bulk electric system elements qualifies as an example of excellence and exemplifies the RTBPTF recommendation of producing a Bulk Electric System Elements List.

Examples of Excellence

EOE-2

Reference — Section 1.2, ICCP-Specific Data
Submitted by — ISO New England

Description

ISO New England and its transmission owners have implemented an automated trouble-tracking system that includes processes and procedures for reporting, notification, tracking, resolution, and escalation of ICCP data problems.

General Information

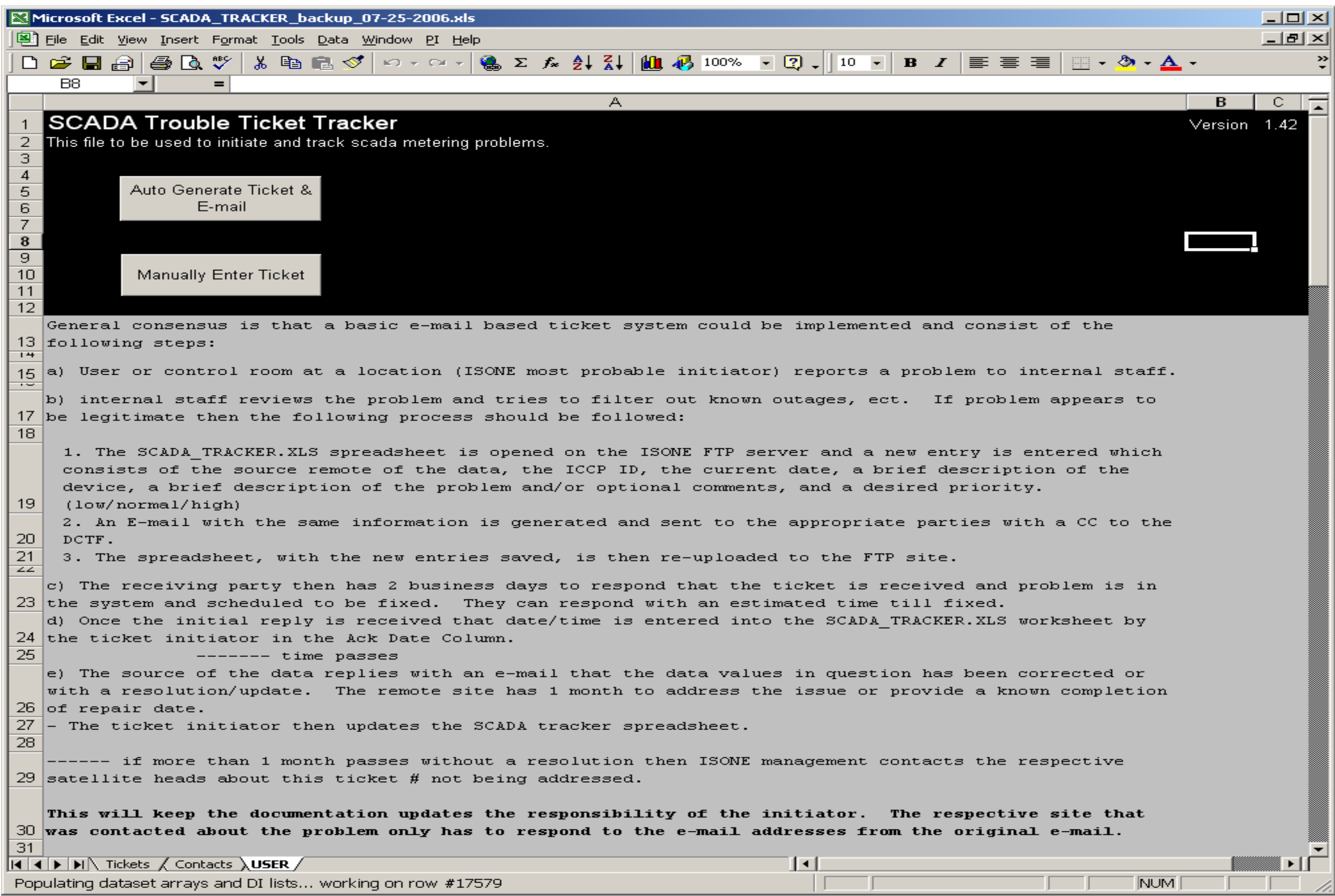
- Tool/Practice Name
  - SCADA TRACKER, a set of procedures, and an Excel spreadsheet system for reporting and tracking the resolution of SCADA data problems related to the New England ICCP network
- Organization Name
  - ISO New England
- NERC Registration (e.g., reliability coordinator)
  - reliability coordinator
  - balancing authority
  - transmission operator
- Contact Name
  - Brock Nubile
- Contact's Official Title
  - Lead EMS Support Specialist
- Contact's Telephone Number
  - 413-540-4210
- Contact's E-mail Address
  - bnubile@iso-ne.com

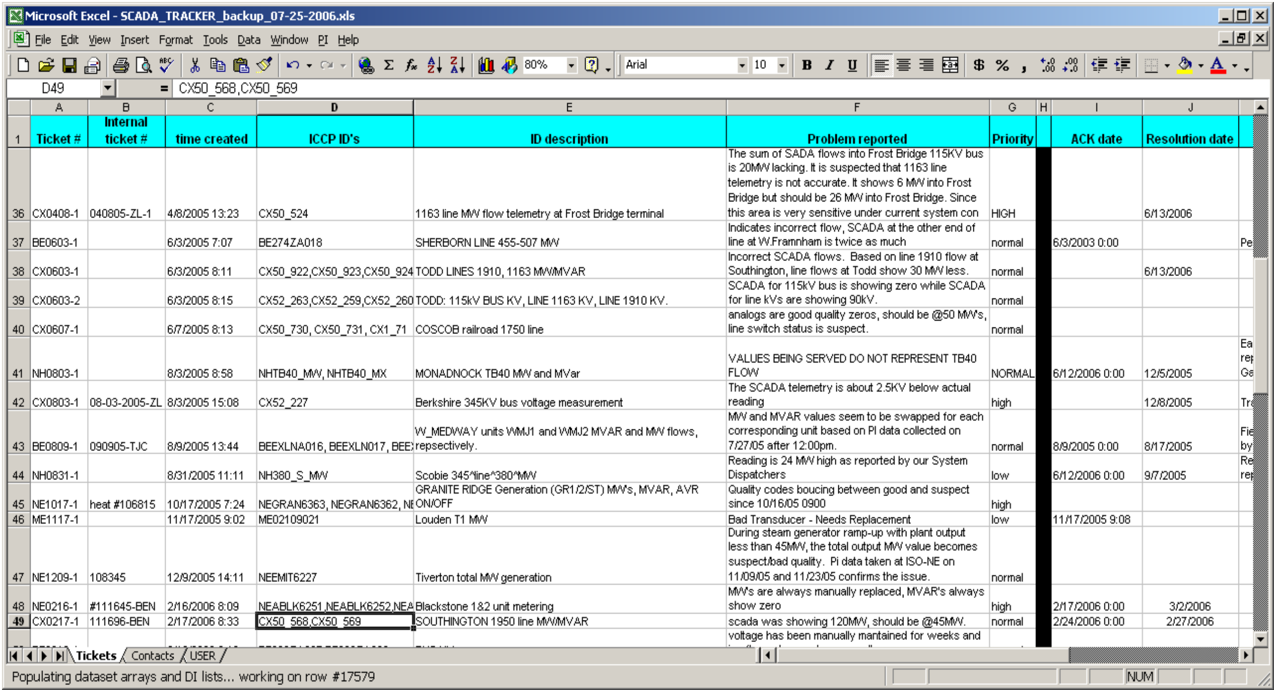
Description of the Tool/Practice

- What does it do?
  - Provides a standard format and procedures for creating trouble tickets related to ICCP SCADA data problems. The Excel spreadsheet contains the procedures, the tracking log, and a set of macros that automatically creates an e-mail message of the ticket to be sent to the appropriate transmission owner/SCADA site. This provides a mechanism for all sites on the network to report data problems that affect all sites on the network. It also provides a log to track resolution of all problems.
- Who uses it?
  - ISO and transmission owner/SCADA EMS support staff
- What are the inputs?

- o Detailed Information about the ICCP data ID with a description of the problem — ICCP ID, data owner, date, problem with the data, and priority rating

- What are the outputs?
  - o Spreadsheet tracking sheet, automatic e-mail message generated
- What is the user interface?
  - o Microsoft Excel spreadsheet; see screenshots below.
- What is/was the alternative practice?
  - o Individual e-mails or phone calls to IT personnel at each site





Microsoft Excel - SCADA_TRACKER_backup_07-25-2006.xls

D49 = CX50_568,CX50_569

	Ticket #	Internal ticket #	time created	ICCP ID's	ID description	Problem reported	Priority		ACK date	Resolution date
36	CX0408-1	040805-ZL-1	4/8/2005 13:23	CX50_524	1163 line MW flow telemetry at Frost Bridge terminal	The sum of SADA flows into Frost Bridge 115KV bus is 20MW lacking. It is suspected that 1163 line telemetry is not accurate. It shows 6 MW into Frost Bridge but should be 26 MW into Frost Bridge. Since this area is very sensitive under current system con	HIGH			6/13/2006
37	BE0603-1		6/3/2005 7:07	BE274ZA018	SHERBORN LINE 455-507 MW	Indicates incorrect flow, SCADA at the other end of line at W.Framnham is twice as much	normal		6/3/2003 0:00	
38	CX0603-1		6/3/2005 8:11	CX50_922,CX50_923,CX50_924	TODD LINES 1910, 1163 MW/MVAR	Incorrect SCADA flows. Based on line 1910 flow at Southington, line flows at Todd show 30 MW less.	normal			6/13/2006
39	CX0603-2		6/3/2005 8:15	CX52_263,CX52_259,CX52_260	TODD: 115kV BUS KV, LINE 1163 KV, LINE 1910 KV.	SCADA for 115kV bus is showing zero while SCADA for line kVs are showing 90kV.	normal			
40	CX0607-1		6/7/2005 8:13	CX50_730, CX50_731, CX1_71	COSCOB railroad 1750 line	analogs are good quality zeros, should be @50 MW's, line switch status is suspect.	normal			
41	NH0803-1		8/3/2005 8:58	NHTB40_MW, NHTB40_MX	MONADNOCK TB40 MW and MVar	VALUES BEING SERVED DO NOT REPRESENT TB40 FLOW	NORMAL		6/12/2006 0:00	12/5/2005
42	CX0803-1	08-03-2005-ZL	8/3/2005 15:08	CX52_227	Berkshire 345KV bus voltage measurement	The SCADA telemetry is about 2.5KV below actual reading	high			12/8/2005
43	BE0809-1	090905-TJC	8/9/2005 13:44	BEEXLNA016, BEEXLN017, BEE)	W_MEDWAY units WMJ1 and WMJ2 MVAR and MW flows, repsectively.	MW and MVAR values seem to be swapped for each corresponding unit based on PI data collected on 7/27/05 after 12:00pm.	normal		8/9/2005 0:00	8/17/2005
44	NH0831-1		8/31/2005 11:11	NH380_S_MW	Scobie 345^line^380^MW	Reading is 24 MW high as reported by our System Dispatchers	low		6/12/2006 0:00	9/7/2005
45	NE1017-1	heat #106815	10/17/2005 7:24	NEGRAN6363, NEGRAN6362, NE	GRANITE RIDGE Generation (GR1/2/ST) MW's, MVAR, AVR ON/OFF	Quality codes boucing between good and suspect since 10/16/05 0900	high			
46	ME1117-1		11/17/2005 9:02	ME02109021	Louden T1 MW	Bad Transducer - Needs Replacement	low		11/17/2005 9:08	
47	NE1209-1	108345	12/9/2005 14:11	NEEMIT6227	Tiverton total MW generation	During steam generator ramp-up with plant output less than 45MW, the total output MW value becomes suspect/bad quality. Pi data taken at ISO-NE on 11/09/05 and 11/23/05 confirms the issue.	normal			
48	NE0216-1	#111645-BEN	2/16/2006 8:09	NEABLK6251,NEABLK6252,NEA	Blackstone 1&2 unit metering	MW's are always manually replaced, MVAR's always show zero	high		2/17/2006 0:00	3/2/2006
49	CX0217-1	111696-BEN	2/17/2006 8:33	CX50_568,CX50_569	SOUTHINGTON 1950 line MW/MVAR	scada was showing 120MW, should be @45MW.	normal		2/24/2006 0:00	2/27/2006
						voltage has been manually mantained for weeks and				

Tickets / Contacts / USER

Populating dataset arrays and DI lists... working on row #17579

Reliability/Situational Awareness

- How does it enhance reliability and/or situational awareness?
  - o Improves repair times for SCADA data by getting the appropriate information to the correct staff in a timely fashion
  - o Broadcasts trouble report to all transmission owner sites so all parties are aware of the problem
  - o Provides a tracking mechanism to identify the current status of a data problem and helps identify data values with repeated problem
- Which reliability standard(s) does it help meet or exceed?
  - o IRO-003
  - o IRO-005
  - o TOP-006
  - o TOP-005
  - o COM-001

Support and Maintenance Issues

- What did it take to implement?
  - o Group agreement to parameters and procedures, appropriate contact lists developed, minor macro programming within Excel
- What does it take to maintain?
  - o Enhancements to tool made upon request and review of ISO-NE's Data Communications Task Force
  - o Each submitter must update log with acknowledgment and resolution date

Examples of Excellence

EOE-3
Reference — Section 1.2, ICCP-Specific Data
Submitted by — ISO New England

Description

ISO New England and its transmission owners have implemented an automated monitoring system that periodically compares data set time stamps to detect and alarm any data sets that have stopped updating for any reason.

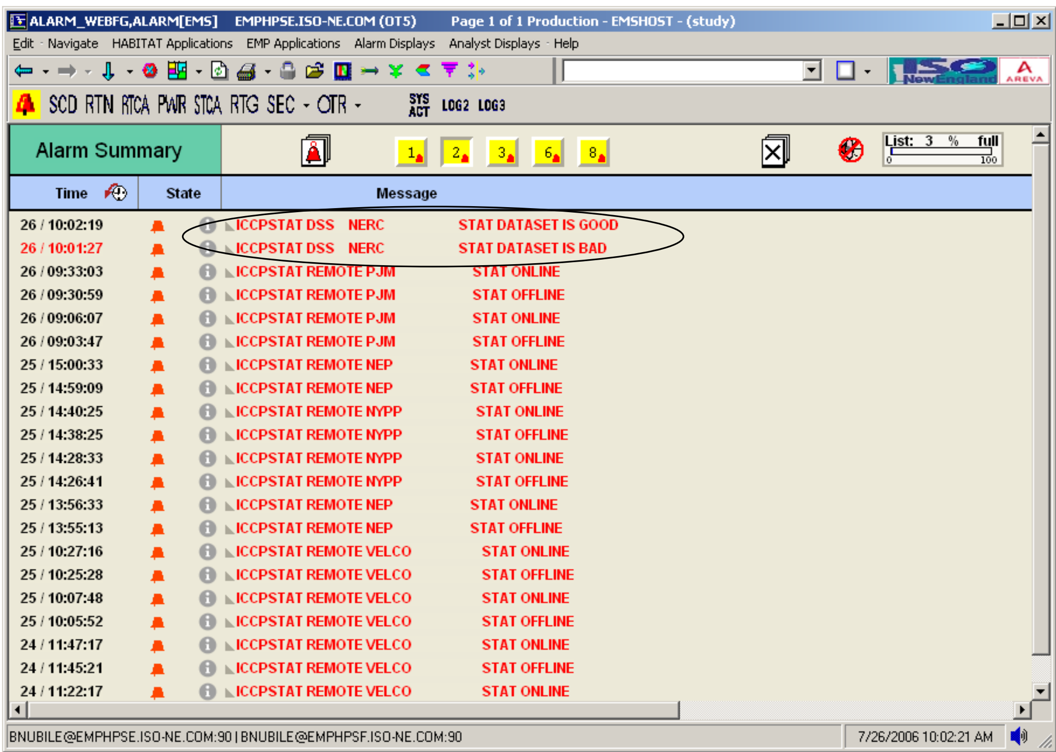
General Information

- Tool/Practice Name
  - DSMON (Data Set Monitor), an in-house designed and written PERL program that monitors all inbound and outbound ICCP server data sets on our vendor-based ICCP servers to confirm that they are transferring data
- Organization Name
  - ISO New England
- NERC Registration (e.g., reliability coordinator)
  - reliability coordinator
  - balancing authority
  - transmission operator
- Contact Name
  - Brock Nubile
- Contact's Official Title
  - Lead EMS Support Specialist
- Contact's Telephone Number
  - 413-540-4210
- Contact's E-mail Address
  - bnubile@iso-ne.com

Description of the Tool/Practice

- What does it do?
  - Every 90 seconds the program dumps a list of all ICCP data-base data sets and compares the last transfer set time to real time while accounting for the data-set transfer parameters. If delta exceeds a threshold, an alarm is issued to the operators on the EMS. This program detects and alarms any data sets that are interrupted because of:
    - Data-base modeling errors when remote sites perform updates (most common)
    - ICCP application software bugs, memory leaks, or extended run times
    - Severe network problems in which ICCP associations cycle frequently (a failed data set is usually the first symptom)

- Who uses it?
    - o Dispatchers and IT support staff
- What are the inputs?
    - o Vendor-based ICCP database, time-synchronized local ICCP server clock, user-entered run-time periodicity
- What are the outputs?
    - o GOOD/BAD status for each ICCP remote's data sets in the form of an ICCP server log file, vendor-based ICCP server data-base values, EMS-based operator alarms
- What is the user interface?
    - o Native EMS-based alarms
- What is/was the alternative practice?
    - o No alternative; this type of monitoring and alarming not offered by the vendor



Reliability/Situational Awareness

- How does it enhance reliability and/or situational awareness?
    - o Alerts operators and IT staff that large portions of data are not updating even though ICCPLINK is still connected and "UP"
    - o Allows IT staff to pursue correcting problem either locally or remotely
- Which reliability standard(s) does it help meet or exceed?
    - o IRO-003

    - IRO-005
    - TOP-005
    - TOP-006
    - COM-001

Support and Maintenance Issues

- What did it take to implement?
    - PERL programming, data-base additions on ICCP and EMS system, training for operators and support staff to respond to the new alarm
- What does it take to maintain?
    - No special maintenance required

Examples of Excellence

EOE-4
Reference — Section 2.2, Visualization Techniques
Submitted by — Northeast Power Coordinating Council (NPCC)

Description

Tool/Practice Name:	Facilitated Transaction Checkout (FTC)
NERC Registration:	Reliability Coordinator
Contact Name:	John M. Simonelli
Contact's Official Title:	Manager Operations Support Services
Contact's Telephone Number:	(413)535-4157

Overview

Historically, the accuracy associated with transaction checkout between those entities tasked with maintaining reliability has been an important industry issue as recognized by both the NERC Operating Committee and its Interchange Subcommittee. In recognition of the reliability concerns associated with transaction checkout and findings from the August 2003 Blackout, elected to undertake a region-wide effort towards improving transaction accuracy.

The NPCC FTC is a tool implemented by all balancing authorities within the NPCC region. PJM expects to implement FTC in the near future, and MISO expects to implement FTC during the fourth quarter of 2006. The tool is a message structure that enables neighboring reliability entities to query each other's transaction stacks and perform an automated comparison prior to performing verbal checkout. This is accomplished through programmatic data exchange using a standard set of protocols agreed to by the NPCC reliability entities. Because the tool is the communication behind the display, the results can be seamlessly integrated into existing EMS applications. The FTC process provides for the data to be easily integrated into existing displays to meet the unique needs of the different balancing authority operators. FTC does not require third-party intervention or support. The current real-time transaction checkout implementation focuses on transactions between entities using the required NERC e-tag as a common identifier. With slight variations to the standard message structure, the tool can and, in some current instances, is being used for Day Ahead/Day Prior transaction verification, after the fact schedule reconciliation, actual tie information and metered tie flow information for inadvertent checkout.

Detailed Description

Transaction Checkout is a common term for an inter-regional business process employed by neighboring BA operators in the northeast. During the Transaction Checkout process, neighboring BAs communicate in an effort to reconcile the pending net interchange between the individual BAs. The primary objective of the Transaction Checkout process is to reach agreement on a net interchange between BAs as well as the underlying list of individual transactions for the next hour. These transactions may be derived under the auspices of full financial markets or under the traditional physical bi-lateral systems. In either case, operators must cross-reference the transactions scheduled separately by each BA to ensure that for each transaction scheduled out of a given BA, there is a corresponding transaction scheduled into the neighboring BA.

For the majority of the industry, this is currently a manual business process accomplished via telephone communication by BA operators. Moreover, each operator has extremely limited (if any) visibility of other BA transactions. Cycling through lists of transactions and cross-referencing them with the neighboring BAs (ensuring that both sides have the same information) is a lengthy and labor-intensive process. Since the operator of one BA does not have any visibility into the other BA's transaction stack, the operator must review each transaction to ensure that it matches the transactions expected in the neighboring BA. Currently, operators must repeat this tedious and inefficient process every hour, 24 hours per day, 7 days per week. Moreover, with the recent efforts to reduce bidding and scheduling to 15-minute intervals, the current process may prove unsustainable.

Facilitated Transaction Checkout (FTC) is accomplished through programmatic data exchange using a standard set of protocols agreed to by the NPCC balancing authorities (BA). Each BA is responsible for providing a “service” that allows other BAs to programmatically request and receive transaction data in preparation for checkout procedures. It is important to point out that there is no standard FTC application or user interface. Each BA has the flexibility to incorporate the functionality into their existing BA tools as each sees fit.

The NPCC FTC solution provides tangible efficiency gains in the transaction checkout process. Advancing this solution from a concept to implementation required mutual cooperation and collaboration from neighboring Balancing Authorities in the northeast. Continued collaboration among NPCC members and its neighbors, PJM and MISO, was vitally important to collectively define, develop, and implement a robust FTC solution.

The proposed FTC solution is not intended to fully automate the process of checkout, nor is it aimed at eliminating the critical human function of the operator. Instead, it is designed to assist system operators by equipping them with the most complete, accurate and timely data possible. The purpose is to facilitate the checkout process such that it can be accomplished in less time and with greater accuracy. The fundamental high-level business process of reviewing transactions between BAs will remain the same; the FTC solution simply makes it easier to execute.

Looking beyond the implementation of FTC in the northeast, an additional direct and tangible benefit of the FTC effort has been programmatic flexibility. The technology developed to support FTC is now serving as the foundation in the development of several other NPCC-wide applications, such as after the fact Inadvertent Accounting and real-time tracking of Shared Activated Reserves. NPCC's development of new, automated "wide-area" tools continues to improve operator efficiency and overall system reliability.

Examples of Excellence

EOE-5
Reference — Section 2.2, Visualization Techniques
Submitted by — Southwest Power Pool (SPP)

Description

Tool/Practice Name:	PowerWorld Retriever
NERC Registration:	Reliability Coordinator
Contact Name:	Kevin Bates
Contact's Official Title:	EMS Engineer
Contact's Telephone Number:	(501)614-3288
Contact's E-mail Address:	kbates@spp.org

Overview

Southwest Power Pool utilizes PowerWorld Retriever to provide a system overview as well as alarm using pie charts and flashing lines. The contouring of voltage, state estimator versus SCADA, generation MW and Mvar availability has proven to be useful in reliability coordination as well as system performance from a technical staff perspective.

PowerWorld Retriever provides a geographical overview of the SPP Reliability system and its neighboring areas. Visualization effects include:

- Arrows depict direction and magnitude of line flow
- "Blinking" lines indicate real-time out-of-service elements
- Pie charts alarm for real-time overloads
- Voltage is contoured

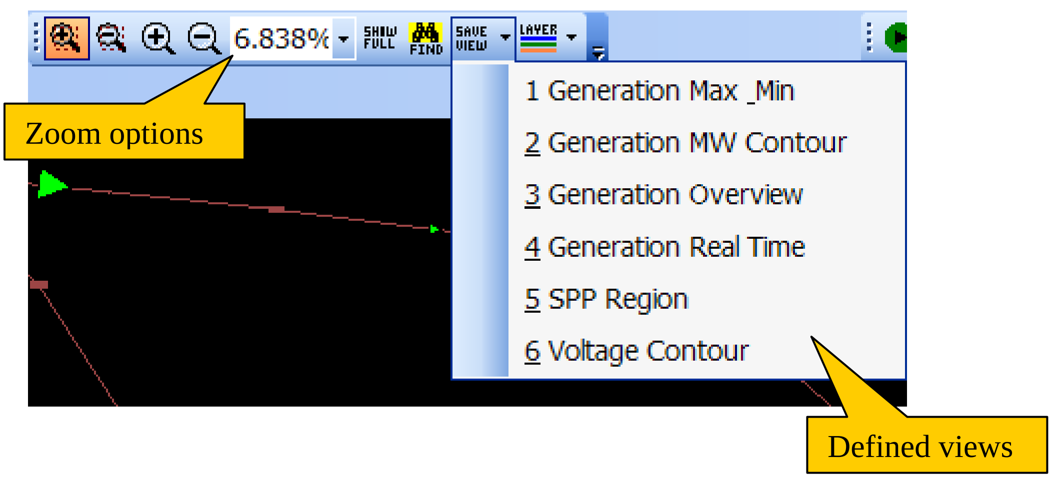
Detailed Description

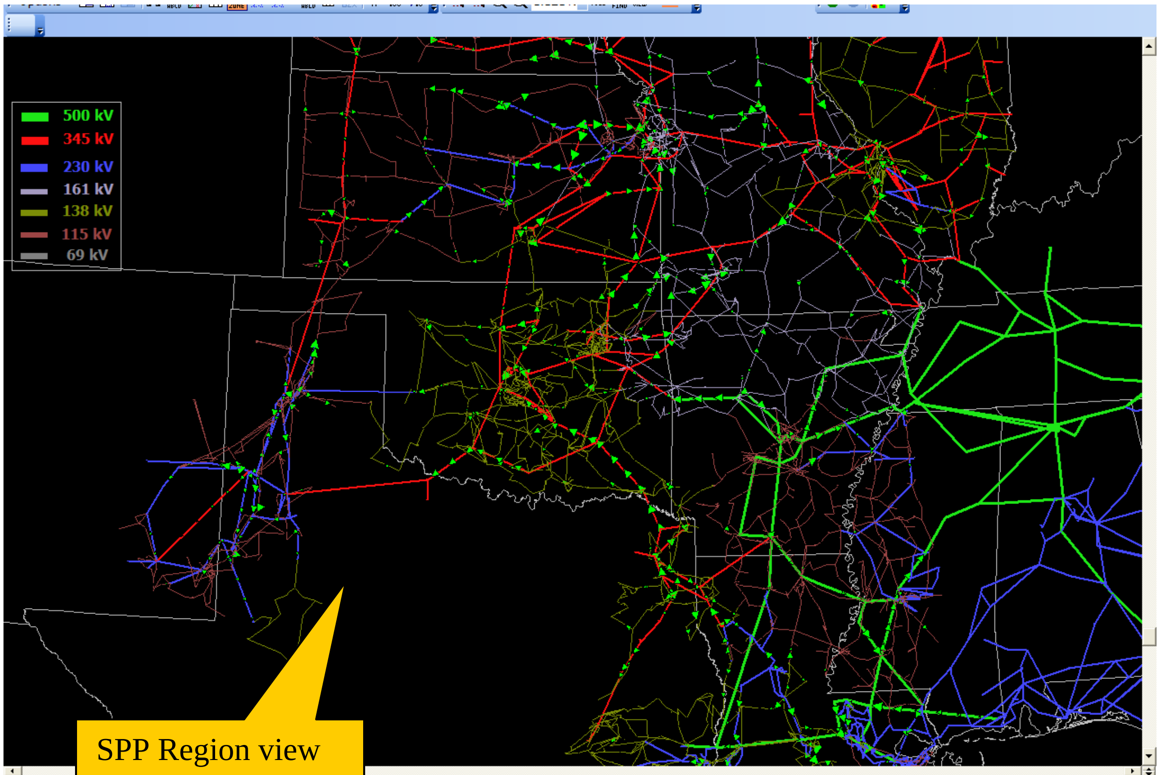
RCs use PowerWorld Retriever as a situational awareness tool in real-time operations as well as training situations. EMS engineers have also used PowerWorld Retriever for contouring differences between SCADA and the state estimator. Since the PowerWorld Retriever model is derived from the EMS model, PowerWorld Retriever has also been used for model verification.

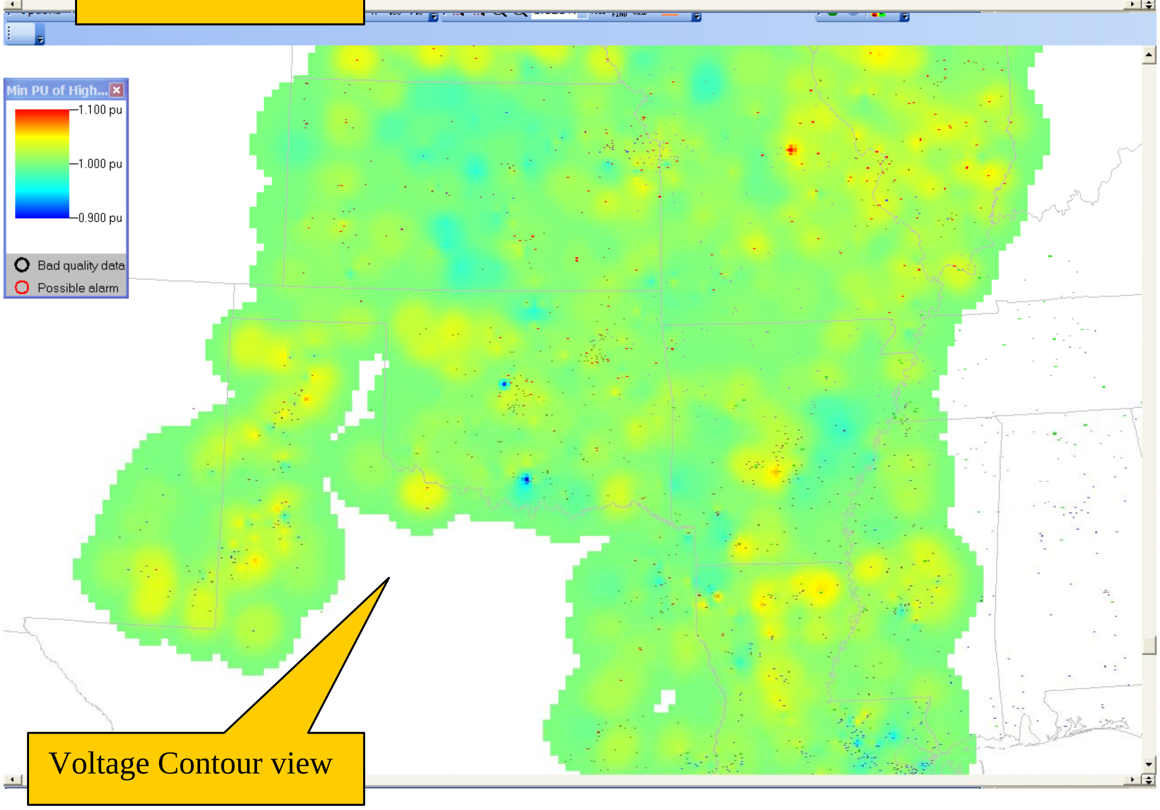
The PowerWorld Retriever model is constructed using the EMS NETMOM model exported via the EMS modeling tool, Genesys. Programs residing on the EMS export SCADA data every 30 seconds and state estimator data every 1 minute from the EMS to text files. Because real-time status for elements is not available from all sources via ICCP, these elements (lines, transformers, generators) have real-time status points defined using real-time status of associated breakers and switches. These points and analogs are placed in flat text files along with a unique alias that identifies a value in the PowerWorld Retriever model. Configuration files loaded to PowerWorld Retriever upon initialization include subscriptions that provide the “links” between these aliases and the PowerWorld Retriever model data fields. These text files can be generated from any EMS system (production, backup, development, etc.), so PowerWorld Retriever can be utilized in training scenarios as well.

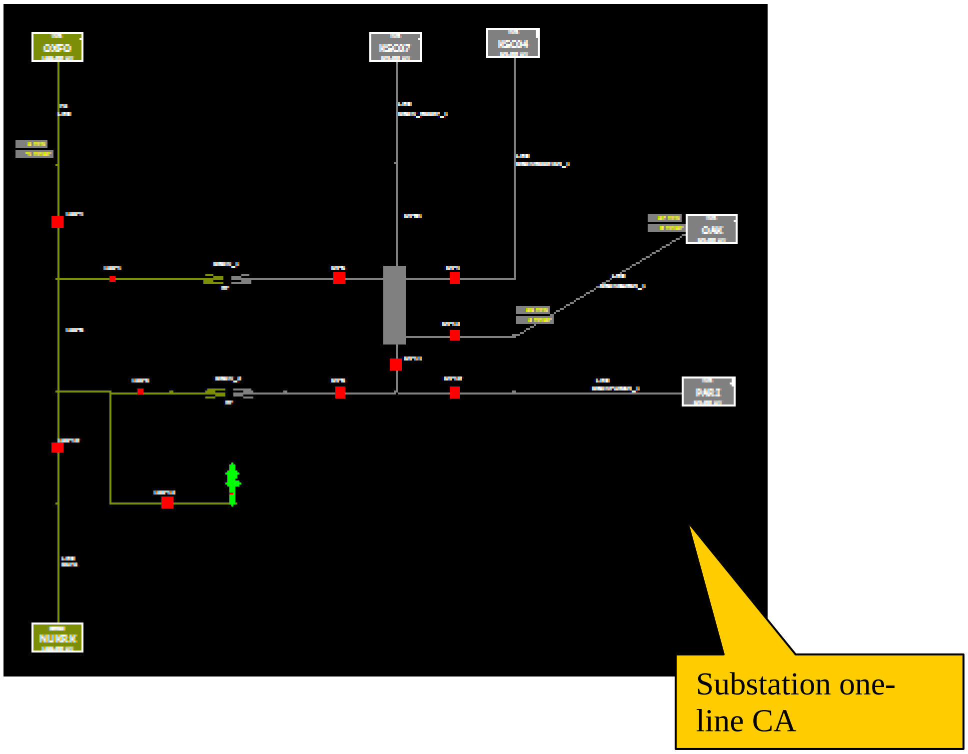
No data outputs are generated by PowerWorld Retriever other than update logs. The data inputs to the model are displayed on associated one-lines which may be geographic or schematic. The aforementioned features (blinking lines, line flow arrows, etc.) are displayed on one-lines that are associated with the underlying model. The text file inputs can be configured to link to any EMS system, therefore resulting in displays showing data from systems used for production, training, or testing.

The interface is typical pull-down menus and toolbars. The most common features used by RCs include navigation tools such as zoom, pan, find, etc. Because of the vast options available, saved views are used to easily navigate between desired displayed data on one-lines. These views have position and layers turned on/off so users are one click from desired views. Case Information tables provide model information and options for sorting, filtering, and exporting. Some substation one-lines are available.




500 kV
345 kV
230 kV
161 kV
138 kV
115 kV
69 kV
SPP Region view


Min PU of High...
1.100 pu
1.000 pu
0.900 pu
Bad quality data
Possible alarm
Voltage Contour view



All data displayed in PowerWorld Retriever are available using EMS displays. They are not depicted in a geographic overview but rather a bus/branch or tabular list. With this tool, RCs are made aware of voltage conditions, real-time flows, and outages for the SPP Region and adjacent regions, which enhances their situational awareness. PowerWorld Retriever helps SPP meet Standard IRO-003-0 by providing a wide-area view of the SPP RC Area and the areas of neighboring RCs.

PowerWorld Corporation was contracted to develop the initial model and overview one-line. SPP and PowerWorld staff integrated an export of the SPP EMS model to the PowerWorld Retriever model structure. Also developed with cooperation of PowerWorld staff were alias and subscription formats used in linking data from the EMS to the PowerWorld Retriever model. SPP also developed programs to export SCADA, state estimator, real-time contingency analysis, and outage scheduler data into text files for uploading to PowerWorld Retriever. Some clean-up and customization of the overview one-line was performed as well as of the view definitions.

Maintenance is performed with each upload of a new EMS model or as needed for modeling corrections. Text files with pertinent modeling information are exported using Genesys. Because PowerWorld Retriever's model structure uses bus numbers that do not correlate with a bus number from the EMS model, a Microsoft Access database is used to maintain consistency between models. This prevents renumbering of one-lines during bulk uploads of a new model. Only new or deleted devices need addressed on associated one-lines. This database also allows for export of aliases and subscriptions used for compiling configuration files used by PowerWorld Retriever.

Examples of Excellence

EOE-6
Reference — Section 2.2, Visualization Techniques
Submitted by — Midwest ISO

Description

Tool/Practice Name: Wide-Area Overview
NERC Registration: Reliability Coordinator

Overview

MISO implemented an expansive wide-area overview display with underlying BA and one-line displays. MISO also incorporated the following into its visualization tools:

- A flowgate monitoring tool that uses LODFs calculated every 10 seconds. This display also includes a provision for dynamic ratings or operating guides.
- A set of reactive monitoring display "delta" tools that visualize sudden changes in generator output or transmission facility flow.

Examples of Excellence

EOE-7
Reference — Section 2.2, Visualization Techniques
Submitted by — American Transmission Company

Description

Tool/Practice Name: Wide-Area Overview
NERC Registration: Reliability Coordinator

Overview

ATC utilizes an application that interfaces directly with its EMS to provide system operators with a dynamic wide-area overview of ATC's network topology as well as state estimation of the neighboring systems. The one-line display (wide-area overview representation) is created automatically from the data within the network model (internal and external). When new equipment is added, the wide-area overview display automatically updates. The wide-area overview provides the operator with actual flows, indications of open lines, and visual indication for lines approaching thermal limits. ATC's operators can dynamically select what is displayed, zoom in or out, and pan across the system. In addition to displaying a wide-area overview, system operators can filter, sort, and query the data to better analyze the power system.

Examples of Excellence

EOE-8
Reference — Section 2.5, State Estimator
Submitted by — Midwest ISO

Description

Tool/Practice Name: State Estimator
NERC Registration: Reliability Coordinator

Overview

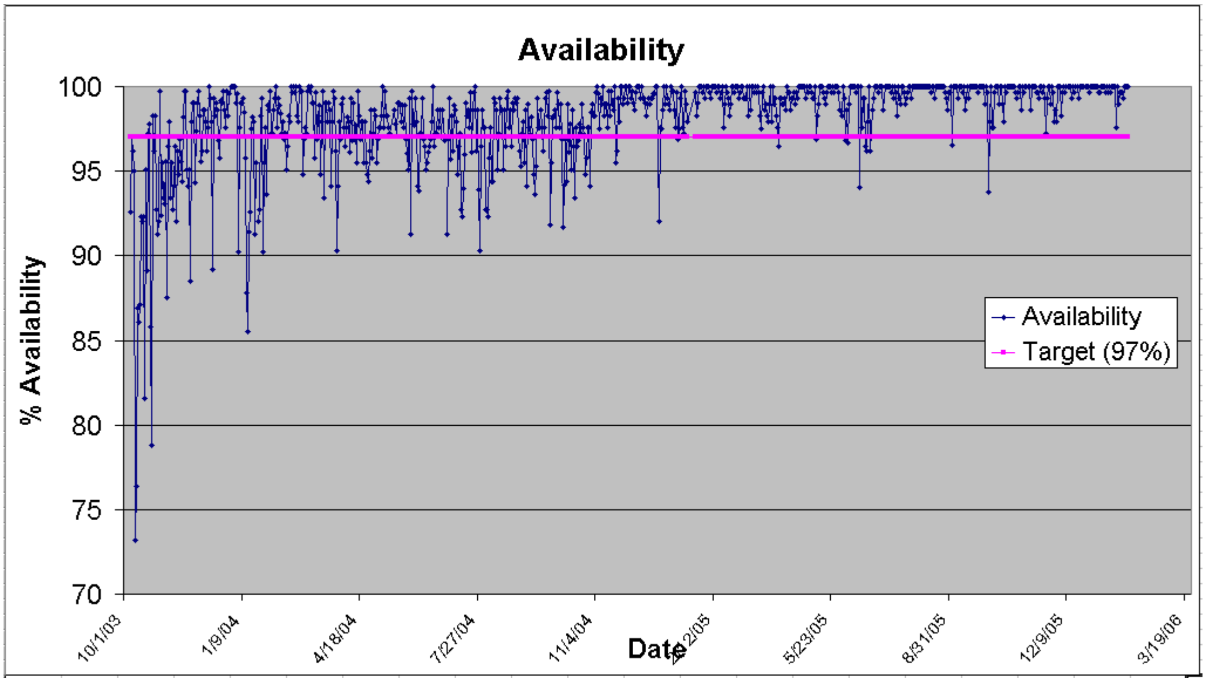
MISO has developed a state estimator solution summary spreadsheet that is used to track solution availability and solution-quality metrics such as solution mismatch, status, convergence, and error tracking for select branch flows, bus voltages, and tie-line flows.

Detailed Description

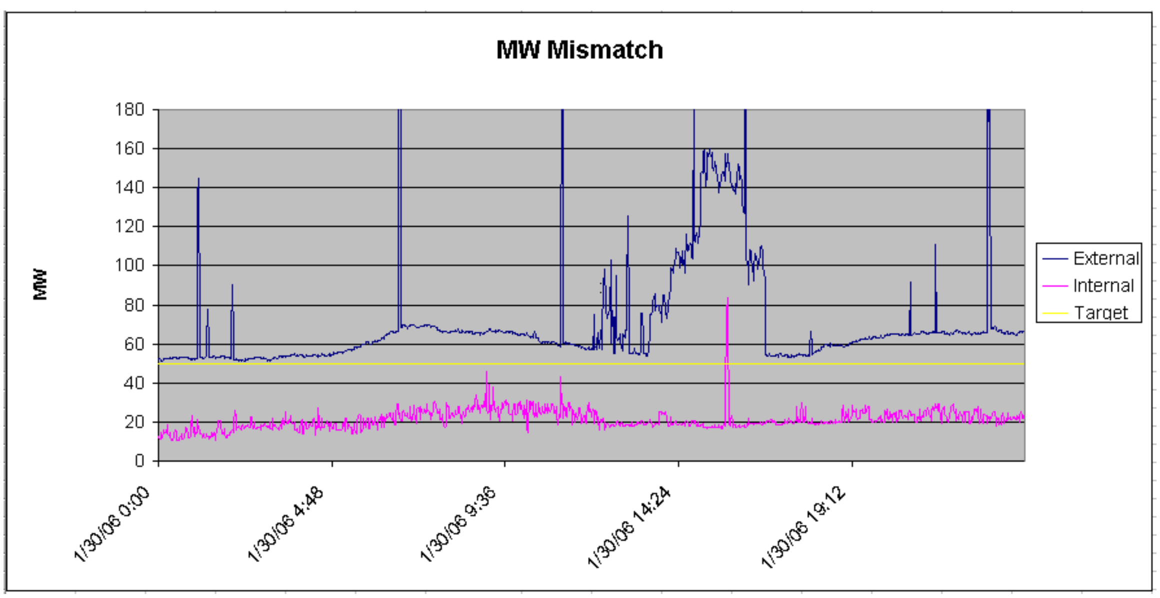
The "home page" of the summary is shown below and includes explanations of what each metric represents.

SE Solution Summary	**01-30-2006** **12:00:00 AM - 11:59:59 PM** Import Data Into Spreadsheet	
State Estimator Metrics Plots	**Plot Explanation**	
State Estimator Availability	**MISO and Transmission Owners require 97% availability. This metric describes the number of 5 minute periods in a day that had a state estimator solution. In a day there exists 288 5 minute periods, to reach 97% availability MISO needs to have state estimator solutions for 280 or more of those periods.**	SE Availability Plot
State Estimator Solution Mismatch	**MISO and Transmission Owners require < 50 MW mismatch for all companies within the MISO footprint. The mismatch data reported here illustrates solution mismatch for both internal and external companies.**	SE MW Mismatch Plot
State Estimator Solution Status	**Illustrates the solution status for each 5 minute period over a 24 hour period. A point of "1" indicates a valid solution period. A point of "0" indicates that no valid solution occurred during that five minute period.**	SE Solution Status Plot
State Estimator Voltage Convergence	**MISO tracks the state estimator voltage convergence on a solution basis. MISO and the Transmission Owners require the state estimator to run with voltage and/or angle convergence tolerances of 0.002, and maximum MW mismatch of 50 MW.**	Voltage Convergence
50 Flowgate, 10 Tie Line, 30 Bus Metrics	**MISO monitors a list of 50 flowgates, 10 external tie lines, and 30 critical bus voltages. These plots illustrate the % error of the solved value compared to the measured**	50 Flowgate, 10 Tie Line, 30 Bus Metrics

The SE availability plot is shown below. It reveals a dramatic increase in the availability of the state estimator as MISO made preparations for the opening of the market. Market applications depend on accurate and highly available solutions from the state estimator to support locational marginal pricing and congestion management.



The MW mismatch plot shown below illustrates how well the total mismatch for companies within the MISO footprint is kept within the target value.



The availability and solution quality metrics illustrated above as well as others that MISO has developed are excellent examples of the types of state-estimator performance metrics that should be monitored as part of the pilot program recommended above. MISO has clearly demonstrated that it is desirable and practical to develop such metrics.

Examples of Excellence

EOE-9
Reference — Section 2.6, Contingency Analysis
Submitted by — Entergy Corporation

Description

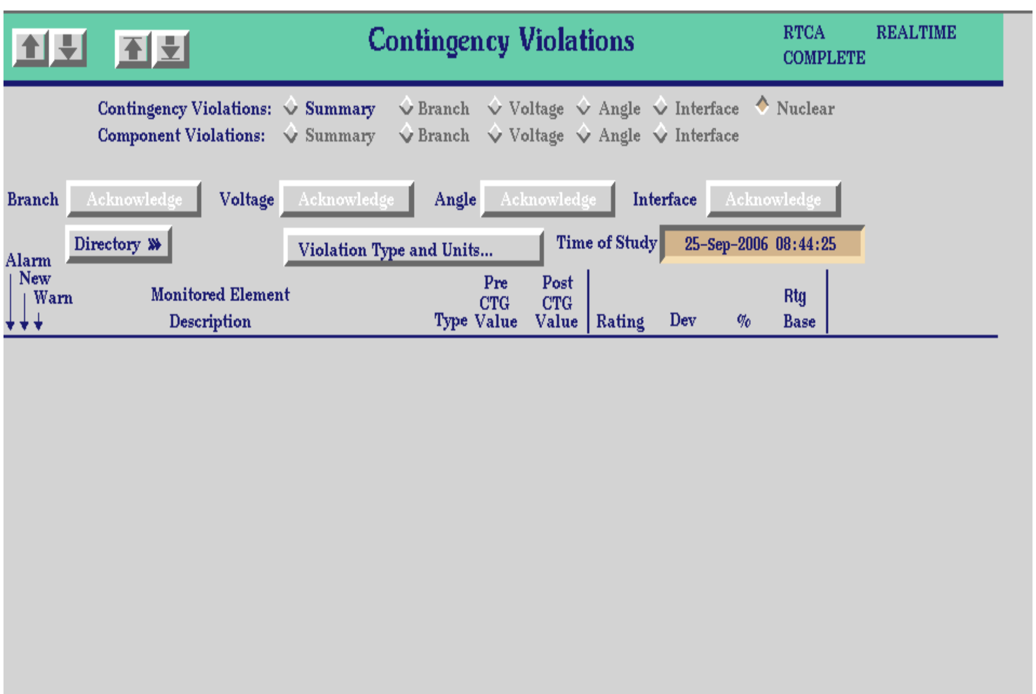
Tool/Practice Name	Utilization of RTCA in Nuclear Offsite Power Monitoring
NERC Registration	Reliability Coordinator, Transmission Operator, Balancing Authority

Overview

Entergy has a real-time contingency analysis application that accurately simulates the effects of loss of a nuclear power plant on switchyard voltage.

Detailed Description

The loss of a nuclear power plant results in the station service load being completely fed by offsite power. To simulate these events accurately, Entergy modified the contingency definitions to add plant load in the event of NPP trip. The real-time contingency analysis at Entergy's control center simulates approximately 1,700 contingencies. To isolate the violations related to NPP offsite power, Entergy also created a separate display that only shows the NPP violations. The following screenshot shows the customized display.



Entergy also developed detailed procedures and operating guides for reporting and acting on NPP offsite power violations. The procedures are summarized below:

Steps to Responding to Violations

Steps 1–3 should be performed within 30 minutes.

1. Verify the validity of the Real-Time Alarm or Post-Contingent Violation.
   a. It is extremely important that all violations are validated prior to continuing with this process.
2. Create State Estimator (RTNET) Save Case to document the violation. The case name should be: “Nuclear_Violation_mm_dd_yyyy_hh_mm”

3. Check the state of the transmission grid for a possible mitigation plan.
   a. Determine if there are any capacitors or reactors in the area that would help relieve the violation.
   b. Determine if there are any transmission equipment outages in the area that are having an impact on the violation.
   c. Determine if there are any generators (Other than the Nuclear Generator) that can be utilized to help relieve the violation. ***The Nuclear Generator can be called to assist with relieving HIGH Voltage, but should NOT be utilized to relieve LOW Voltage.
4. Develop and execute the mitigation plan. This mitigation plan should be capable of relieving the violation without having a negative affect on the reliability of the transmission system. Steps 1-3 must be completed within 30 minutes following the violation.
5. Report the violation to the respective nuclear plant using the following form (Regardless of whether or not the mitigation plan corrected the violation).

   This form should be faxed to the respective nuclear plant and followed up with a phone call to verify the receipt of the fax.

6. If the violation was NOT corrected, proceed to step 7. If the violation WAS corrected no further action will be required. However, be prepared to answer questions from nuclear personnel regarding the violation.

   Fax updated Online Notification Form to the Respective Nuclear Plants and follow up with a phone call to verify the receipt of the fax.

7. If the mitigation plan fails to relieve the violation within 30 minutes or a mitigation plan could not be determined within 30 minutes, contact the on-call support personnel, on-call Duty Chief and the Reliability Coordinator to make them aware of the situation.

   Fax updated Online Notification Form to the Respective Nuclear Plants and follow up with a phone call to verify the receipt of the fax.

8. **Nuclear Conference Call:** If a violation still exists, the nuclear plant will set up a conference call with nuclear and transmission. Once the system operation center (SOC) has been notified of the conference call time by nuclear, the SOC Shift Supervisor will be responsible for notifying the following transmission personnel of the conference call. ***To notify this group you will need to send a page to the "Nuclear Notification" Group using the following text: ***Name, Phone Number***. Nuclear Offsite Voltage Notification made on ***mm/dd/yyyy*** at ***HH:MM***. Conference call will begin at ***HH:MM***. Phone Number: **###-###-####**. Access Number: **#####**

    - Transmission Operational Planning Representative
    - SOC Duty Chief
    - Operations Director
    - System Security - Manager
    - Reliability Coordinator
    - Reliability Coordinator Support
    - TOC Manager for area of discussion

9. Following the conference call, the SOC Shift Supervisor will be responsible for the execution of any additional transmission actions as well as continuing to monitor the violation.

    Fax updated Online Notification Form to the Respective Nuclear Plants and follow up with a phone call to verify the receipt of the fax.

10. Once the violation has ended, the SOC Shift Supervisor will be responsible for sending the nuclear plant the completed Nuclear Notification form and notifying all transmission personnel involved of the end of the violation.

    The form should be faxed to the respective nuclear plant and followed up with a phone call to verify the receipt of the fax.

11. Create State Estimator (RTNET) Save Case to document the violation. The case name should be: "Nuclear_Violation_mm_dd_yyyy_hh_mm"

The process also requires operators to monitor availability of real-time contingency analysis and the state estimator. Entergy also established a procedure to notify nuclear power producers in the event of unavailability of real-time contingency analysis or the state Estimator. The procedure is outlined below. These procedures are only applicable for notifying nuclear plants.

Steps to take when the state estimator is unavailable:

1. Document the time that the state estimator became unavailable. Report the unavailability to EMS on call person.
2. Can the state estimator be restored in <1 Hour?

a. **YES:** Continue to monitor on how long the state estimator has been down. If the restoration time exceeds 1 Hour, proceed to step 2b.
b. **NO:**
    i. Contact the on-call Operations representative.
        1. Verify that the Offline Nuclear Monitoring System is available.
        2. Discuss any unplanned system changes that have occurred since the last time Operations ran the nuclear offline study.[8] If changes have occurred, request that Operations rerun the nuclear study to check for any issues.
    ii. Verify that the SOC EMS system is functioning.
        1. **If SOC EMS System is <u>NOT</u> functioning:** Contact each Transmission Operation Center (TOC) that has a nuclear plant within its system and request that it notify the SOC if any low-voltage alarms are received at any substation near the nuclear plant. Proceed to iii.
        2. **If SOC EMS System <u>IS</u> functioning:** Continuing to monitor for any nuclear voltage alarms. Proceed to iii.
    iii. Notify each nuclear plant using the following form.

        This form should be faxed to the respective nuclear plant and followed up with a phone call to verify the receipt of the fax.

3. After the state estimator has retuned to service and the SOC EMS is functioning correctly.
    a. If the nuclear plants were previously contacted in the above step, notify each nuclear plant using the same form as above.

        The form should be faxed to the respective nuclear plant and followed up with a phone call to verify the receipt of the fax.

    b. If the SOC EMS System was not functioning correctly and the TOCs were requested to monitor real-time voltage alarms around the nuclear plants, contact the TOCs and inform them that the SOC EMS System is now functioning correctly.

[8] Entergy has also implemented an offline process to monitor the nuclear power plant offsite power for next day.

Examples of Excellence

EOE-10
Reference — Section 2.7, Critical Facility Loading Assessment
Submitted by — PJM

Description

Tool/Practice Name: Thermal Tracking
NERC Registration: Reliability Coordinator

Overview

The Thermal Tracking (TT) critical facility loading assessment nominated by PJM was originally supplied as a standard part of their EMS vendor software but has been subsequently enhanced by PJM. TT is used to screen for transfer interface violations and a number of potentially serious double-contingency violations. Of particular value is the enhanced capability for this application to advise operators of the generation redispatch options to alleviate reported overloads. This tool also acts as a backup should the first-line security analysis functions abort or otherwise degrade.

Examples of Excellence

EOE-11
Reference — Section 2.9, Study Real-Time Maintenance (SRTM)
Submitted by — PJM

Description

Tool/Practice Name: Study Real-Time Maintenance
NERC Registration: Reliability Coordinator

Overview

PJM Regional Transmission Operator (RTOP) can host up to three users of the SRTM function simultaneously in the production EMS environment. The function is typically performed by support staff, not operators. To avoid conflicts, each user of the SRTM function is completely independent of the production real-time system and of any other SRTM users. Each SRTM user interface looks and feels exactly like the production network applications. However, instead of the red window border used to indicate the production real-time system, a green window border is used to clearly distinguish that the user is actually in SRTM mode.

Historical real-time state estimator saved cases are archived automatically every 5 minutes. All non-converged state estimator solutions are archived automatically when they occur. An SRTM user can be initialized from a historical saved case or the current real-time state estimator solution within seconds. All real-time network applications including NTP, CFLA, flowgate distribution factor calculation, state estimator, contingency analysis, and voltage stability are initialized from the saved case or the current real-time solution. All real-time network applications can be run exactly as they were in the real-time production EMS environment; therefore, all problems and results can be reproduced for debugging purposes. An SRTM case can be archived by the user and retrieved at a later time to complete work. An SRTM case can be used to initialize a study power-flow user, in the same manner as from a real-time state estimator case, to simulate the study network applications.

It is important to note that an old case archived from a previous version of the network model may not be compatible with the current version of the network model depending on the number and type of model changes. To avoid this problem, PJM debugs problems as soon as possible after they occur and prior to updating the network model on the production system if possible. If the model has to be updated prior to resolving a problem, the case is used on a non-production EMS system with the previous version of the network model to complete the work. The PJM practice is to debug and resolve all non-converged state estimator solutions, all non-converged contingency analysis solutions, and all non-converged voltage stability solutions using SRTM as quickly as possible.

In addition, any other network application problems identified by PJM staff are debugged and resolved as quickly as possible using SRTM.

SRTM allows PJM to quickly and easily recreate, debug, and resolve network application problems without impacting the real-time network applications and has increased the overall availability of the real-time network applications. The PJM SRTM was provided by the PJM EMS vendor with some customization. Significant initial testing was required to insure that the initialization software was operating correctly to insure that SRTM results exactly matched the production system. The PJM EMS network applications support staff are the primary users of the SRTM. The PJM system operators, reliability engineers and other engineering support staff also use the SRTM. Because SRTM is fully integrated with the production EMS system, it requires little additional maintenance.

Examples of Excellence

EOE-12
Reference — Section 2.10, Voltage Stability Assessment
Submitted by — PJM

Description

Tool/Practice Name:	Real-time Voltage Stability Application
NERC Registration:	Reliability Coordinator

Overview

PJM is working on an enhanced real-time voltage stability application to provide control actions to avoid collapse and increase stability margins.

Examples of Excellence

EOE-13

Reference — Section 2.14, Other Tools (Current and Operational)
Submitted by — Bonneville Power Administration

Description

Tool/Practice Name:	Congestion Management Application
NERC Registration:	Balancing Authority, Transmission Operator

Overview

The Bonneville Power Administration (BPAT) uses a curtailment wizard in its implementation of a congestion management application. This wizard is an effective and key component of BPAT's congestion management tool for the interties. Schedule adjustments are communicated and coordinated among the affected parties via the e-tag. For the network, BPAT has an "interim" curtailment calculator, which targets specific generation and loads. This curtailment calculator can be used on two of the network flowgates. This is an "in-hour" tool and it works effectively by targeting specific generators and loads. However, it lacks a prospective view of upcoming flows and does not support preventing transmission sales that would further exacerbate the congestion. BPAT is currently planning to integrate e-tag curtailments with these "interim" curtailment calculators while pursuing tools to provide a full capability to manage capacities and congestion on their network.

Examples of Excellence

EOE-14
Reference — Section 2.14, Other Tools (Current and Operational)
Submitted by — FirstEnergy (FE) and MISO

Description

Tool/Practice Name:	Real Power-Voltage Stability Analysis Tool
NERC Registration:	Reliability Coordinator, Transmission Operator

Overview

Excerpted from survey comments by an FE representative:

> An operator must maintain an awareness at all times of where the system is operating relative to all limits. FE, in conjunction with the Midwest Independent Transmission System Operator (MISO), utilizes a real power-voltage (P-V) stability analysis tool that determines system operating limits in three critical areas of the FE transmission system. NERC commended the FE/MISO approach to voltage stability analyses as an Example of Excellence in their November 2, 2005 Reliability Readiness Audit and Improvement Program**.**
>
> P-V analysis is used to determine the health of the system by determining the rate of voltage decay at a system bus as the level of real power changes due to system loads or transfers across the system. The "nose" of the P-V curve represents the maximum real power load that can be served or the amount of power that can be transferred beyond which the rate of voltage decay dramatically increases toward voltage collapse. The difference between the real power quantity being monitored in real time and the real power limit at the nose of the curve is the real power operating margin. The MISO reliability coordinators and FE transmission operators monitor the flow on the three critical interfaces in real time to the lower of the voltage collapse limit, the steady-state voltage limit, and the thermal ratings limit. To provide a sufficient operating margin, MISO and FE apply a ten percent power flow safety margin in the next-day analysis and a five percent margin for the current-day analysis in determining the voltage collapse limit the operators will use. Additional analysis is conducted any time a critical facility in the FE area is out of service. For forced or emergency outages, a MISO operations engineer position is staffed around the clock to perform the analysis.

Examples of Excellence

EOE-15
Reference — Section 3.5, Load-Shed Capability
Submitted by — Dominion Virginia Power

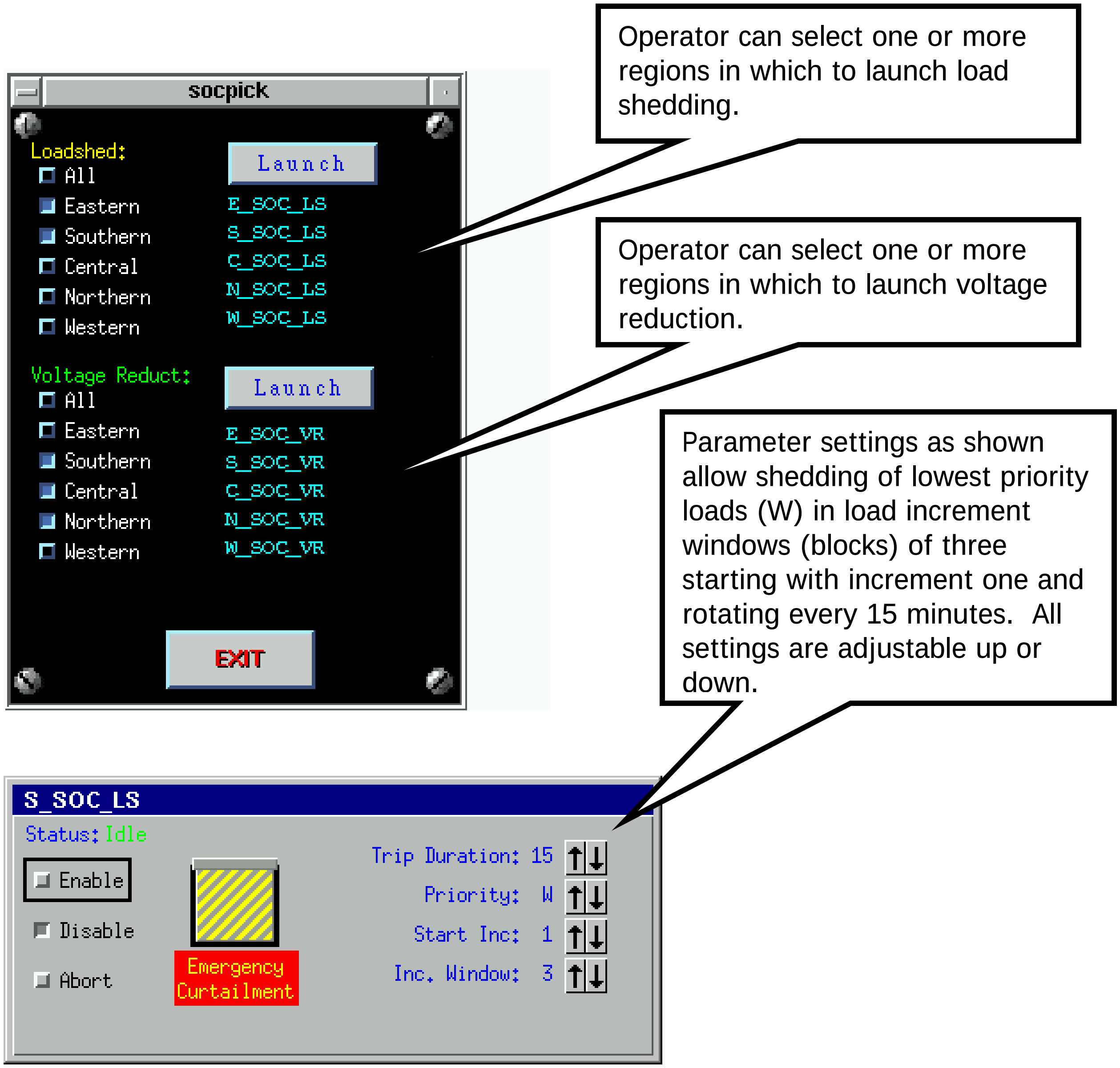
Description

Tool/Practice Name:	Load Shedding/Rotation and Voltage Reduction
NERC Registration:	Transmission Operator

Overview

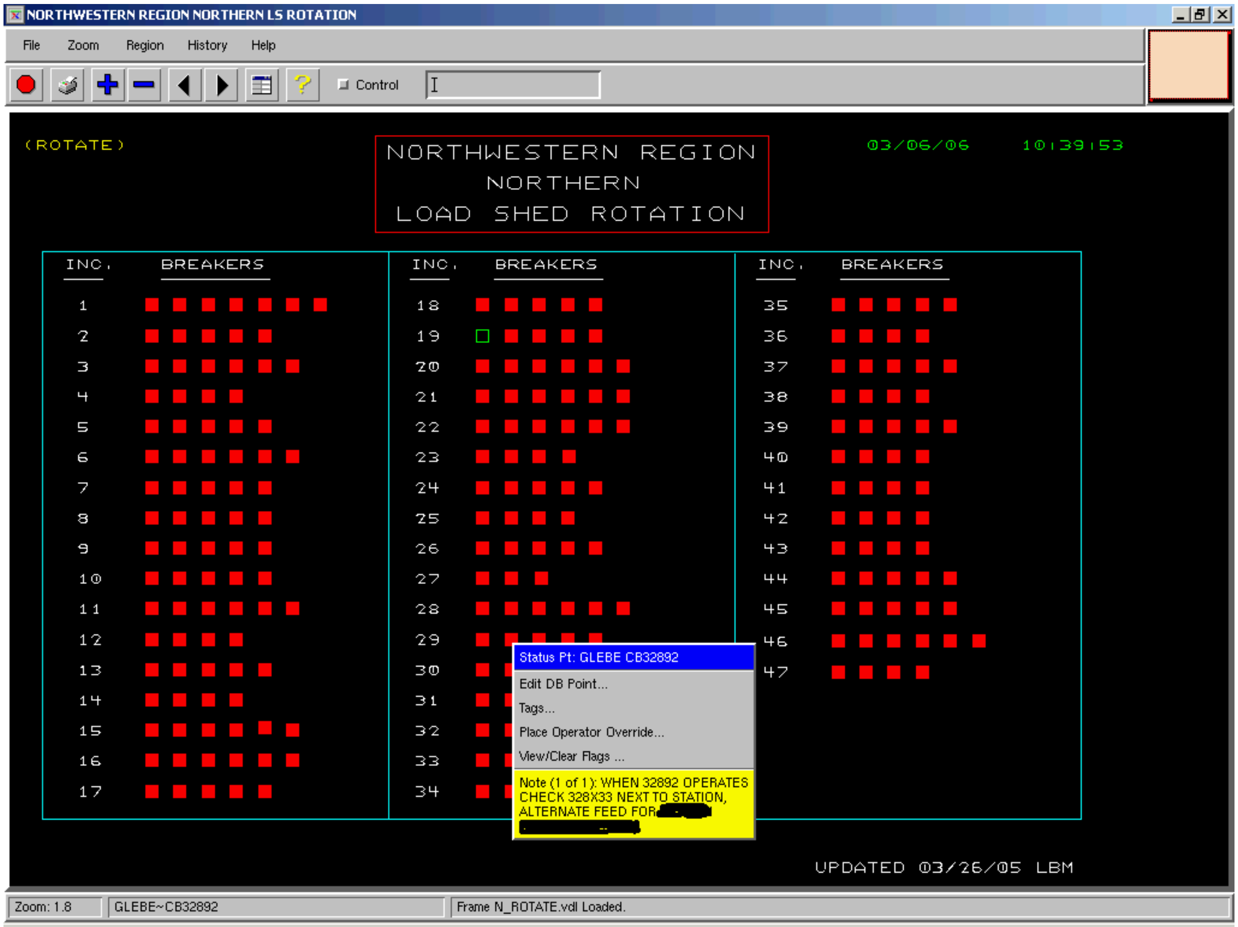
In order to quickly activate the Dominion Virginia Power Load Curtailment Plan, a control application was developed by Dominion to implement load shedding/rotation and voltage reduction. This application runs on the Distribution Management System (DMS), which was developed in house. The application is available to the transmission system operators at the SOC and is also available to the operators at the regional Distribution Operations Centers (DOCs). The program that allows the SOC to implement load curtailment is called SOCpick, and the program that allows the DOC to implement load curtailment is called Loadpick. The main difference between the two programs is the operator interface.

The transmission system operators at the SOC are responsible for implementing load shedding and voltage reduction at the direction of the RC. They can perform this function from their user interface at the SOC or they can request assistance from the regional operators in the three DOCs. The following screen shots show the SOCpick user interface for launching a system-wide or regional load-shed operation or voltage reduction and the user interface for adjusting the load-shed program parameters including trip duration, load priority (W — the lowest, X, Y, or Z — the highest), starting load increment, and load increment window.

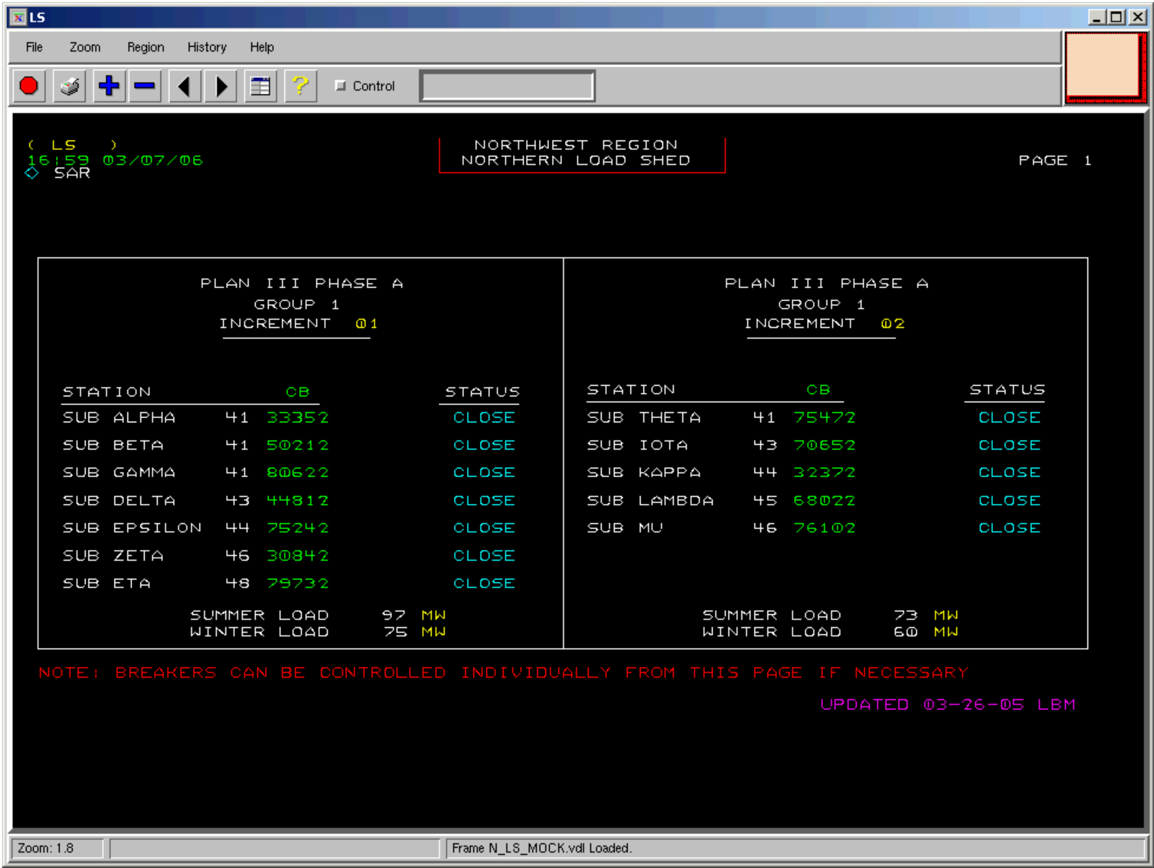


The following screen shot shows the status of each distribution breaker in each load-shed increment (block) in the northwestern region. There are a total of 47 increments in this particular region. In addition to showing the open/close (green/red) status of each breaker, placing the cursor over the breaker symbol generates a pop-up window that identifies the associated substation, breaker number, and other specific information related to the status of the circuit. Any breaker that has a tag on it will have a “T” appear next to it on this screen, and any breaker with a special note associated with it with will have an “N” appear next to it. In the example below, the “N” next to the breaker for circuit 32892 at the Glebe substation is obscured by the pop-up window that identifies the breaker. The pop-up also includes an operating note (redacted for security reasons) highlighted in yellow.

Not only can the status of individual circuits be monitored at any time from this screen, but once load shed is implemented, the progress of load-shed rotation can be monitored as well.

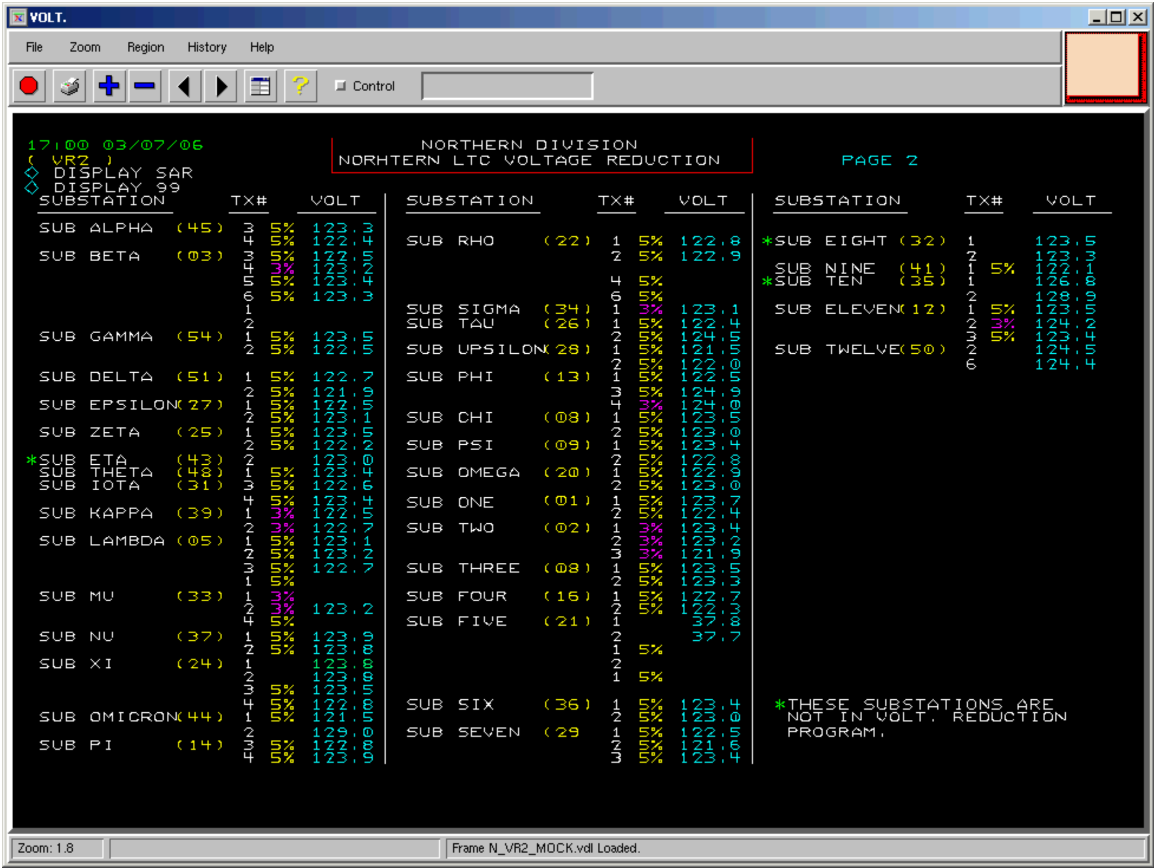


The next example screen shows another view of the individual circuits in the load-shed increments. The circuits that are part of increments 1 and 2 in the northwestern region are shown on this page along with their status and the substations in which they are located. The actual substation names have been replaced with aliases for security reasons. Also shown is the estimated load in each increment that is subject to being shed. These load estimates are based upon historical seasonal peaks.

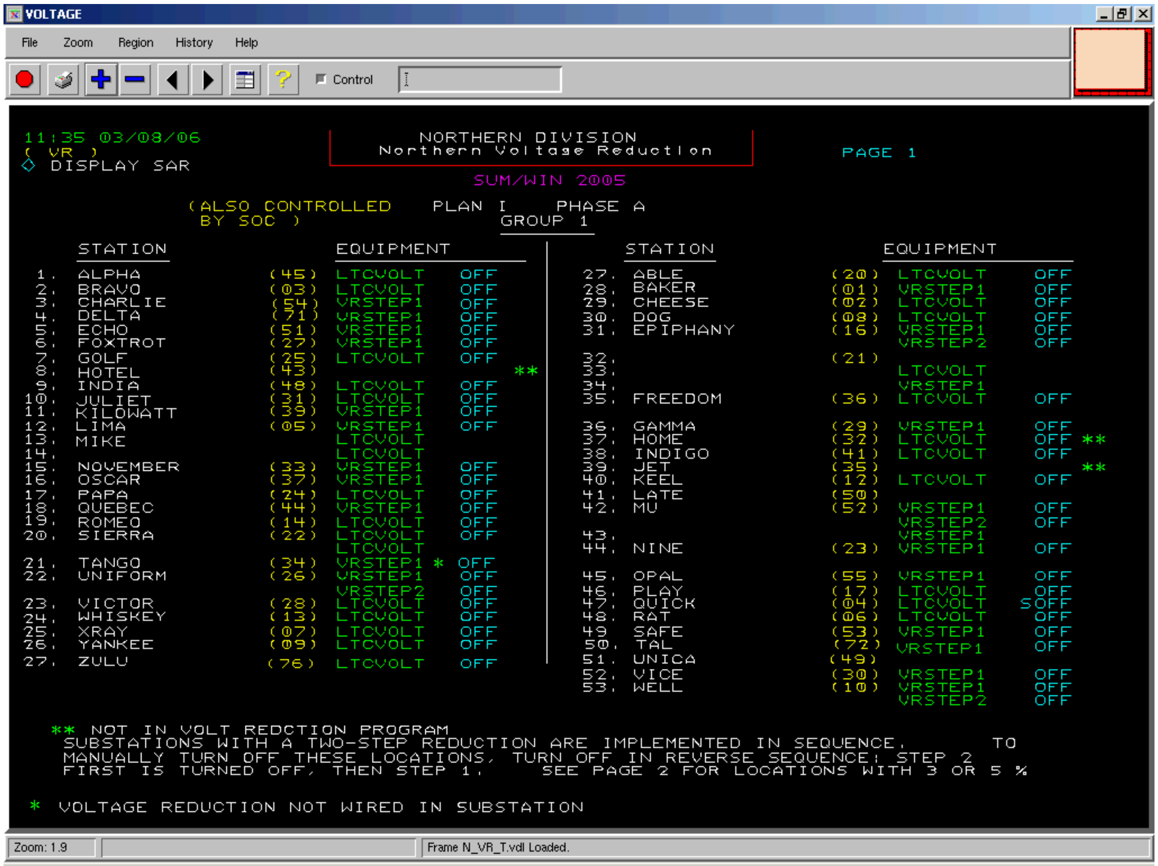


Prior to the development of this application, the previous practice for operator-controllable load-shed was to have the SOC operator (and the DOC operator at the direction of the SOC) use the SCADA systems to send individual circuit breaker trip and close commands to the various substations with circuits eligible for controlled load shedding as identified in the load curtailment plan. This was very time consuming, involved many different substation displays, and made load-shed rotation extremely difficult. Having the load-shed application enhances reliability and situational awareness by allowing quick response to a load-shed directive and overview monitoring of load-shed facility availability and expected response.

The following screen example shows all of the transformers at substations in Dominion's northern division that are controllable for voltage reduction. The actual substation names have been replaced with aliases for security reasons. This screen shows the reduction percentage (3 percent or 5 percent) that is available from each transformer along with the real-time voltage on the associated bus potential transformer secondary (the approximate single-phase voltage that the customers see).



The following screen example shows the status of the voltage reduction equipment at each substation in Dominion's northern division. The actual substation names have been replaced with aliases for security reasons. Equipment statuses preceded by an "S" such as is shown for substation "Quick" on the screen example means that a special order tag has been placed on the equipment. Special order tags usually indicate that some restriction has been placed on the operation of the equipment.



The in-house development of the software to facilitate load shedding and voltage reduction was based upon Dominion's operating needs for implementing its load curtailment plan. System operators provided critical input and feedback during the development. In addition to routine software maintenance of the application performed by the IT staff that supports the DMS, there is an annual, end-to-end load curtailment equipment test to verify correct operation.

Examples of Excellence

EOE-16
Reference — Section 3.6, System Reassessment and Re-posturing
Submitted by — VACAR Subregion of SERC

Description

Tool/Practice Name:	VACAR Guidelines For Addressing Situations Outside of Established Procedures
NERC Registration:	Reliability Coordinator, Transmission Operator, Balancing Authorities

Overview

The VACAR Subregion of SERC has developed documented guidelines to address events on the transmission system that are outside the scope of established operations. These guidelines, which are part of the *VACAR-South Reliability Coordinator Handbook*, are intended for use by the RC working in close coordination with the BAs (TOPs) within the reliability area. These guidelines contain several excellent examples of what to include in a procedure for reassessing and re-posturing the system following an event or events that leave the system in an insecure or unstudied state.

Particularly noteworthy is the section describing a generic approach to problem solving. This approach encompasses assessing the situation, diagnosing the problem, planning corrective actions, implementing the plans, and assessing after the fact the appropriateness of the actions taken. It also stresses communications and coordination among affected parties

The document follows in its entirety.

Procedure Name: Guidelines for Addressing Situations
Revision Date: 1/24/2005
Outside of Established Procedures

VACAR GUIDELINES FOR ADDRESSING SITUATIONS OUTSIDE OF ESTABLISHED PROCEDURES

Purpose

This guideline provides a framework for the reliability coordinator (RC) to use in addressing situations outside of established procedures. The RC shall rely heavily on system expertise that the Control Area (CA) operators have relative to the local area operation of their own systems with regard to problems that may result in the use of this procedure.

Conditions

Various types of conditions may become apparent to the RC that are not addressed in the current Emergency Operating Procedures (EOP). These may include:

• **Over voltage** conditions on a Member system: The RC shall coordinate with the CAs and other RCs to check the status of capacitor banks, voltage control devices, regulated volt-ampere reactive (VAr) reserves. If necessary, the RC will coordinate the removal of lightly loaded Extra High Voltage (EHV) facilities from service or insertion of reactive devices within the affected CA or neighboring CAs.

• **Under voltage** conditions on Member systems: The RC shall coordinate with the member CAs and other RCs to check the status of capacitor banks, voltage control devices, and regulated VAr reserves. If the condition still persists following the validation of the status of all VAr resources, the RC may need to review sales/wheeling schedules for their impact on voltage. It may also be necessary for the CA to consider redispatch of generation.

• **For first contingency transmission overloads** on the bulk transmission network that need to be relieved within a thirty **(30) minute** time frame, the appropriate procedures will be implemented to relieve the overloaded facility. This may include any available local operating procedure or NERC Transmission Loading Relief Procedure (TLRP).

• **For transmission overloads** on the bulk transmission network that need to be relieved immediately, methods listed below will be used to relieve the overloaded facility.

- Removing from service other transmission facilities in the area, which will off-load the overloaded facility.
- Removing from service the overloaded facility itself.
- Return to service any available outaged facilities that will help off-load the overloaded facility.
- Redispatch generation.
- Curtail energy and transmission schedules
- Curtail interruptible customers

• **Stability** of the interconnected network may become a concern of the RC and CA(s). If this is identified as a problem, the RC and the affected CA and other RCs should:

- Verify network topology
  - Determine if local conditions are contributing to the stability problem,
  - If local conditions are not a contributing factor, notify neighboring sub-regional and regional RCs

- Verify the status of Power System Stabilizers (PSSs) in the area.

Problems in other Reliability Coordinator's Security Areas

The problems discussed above (over- and under-voltage, contingency, and stability) may exist in other RC's Reliability Areas and resolution will require coordination between VACAR and these other areas. To the extent that VACAR CAs impact these external problems, the VACAR RC will work, in the manner described above, with those CAs and other RCs to rectify the situation.

Generic Approach to Problem Solving

Should all the above fail to correct problems on the bulk interconnected network under the responsibility of the VACAR RC or problems which the VACAR RC has been requested to help alleviate, the VACAR RC should attempt to solve the problem utilizing a generic approach to problem solving, which will continue to utilize contact with the affected CAs and other RCs. This approach involves five (5) steps. This diagnostic process can aid the RC and system operators in addressing problem situations in a systematic manner. The RC should rely heavily on system expertise that the CAs and other RCs have relative to the local area operation of their own systems with regard to problems that may result in the use of this procedure.

- **Assessment of Situation:** This involves assembling data that is available to the RC, gathering additional data from remote sites and/or systems, and evaluating the evidence. From the large amount of data available, the RC must focus on the data that is critical to the problem. Throughout the process, the RC should remain alert for new data and be prepared to integrate all evidence received. As part of the immediate assessment of the situation, the RC must decide the urgency of the problem and the need for decision or action.

- **Diagnosis of Cause of Problem:** This step involves formulating alternative interpretations of the event, gathering additional information as needed to support or refute the interpretations, and finally determining the most probable cause of the problem. The RC should retain an open mind in reviewing the evidence and examining different possible causes of the problem. Knowledge of previous incidents and of system/equipment history should be used in formulating explanations. A team brainstorming approach including RC and CA resources can be helpful in maintaining the openness at this point in the problem solving process. Once explanations have been formulated, additional information that would help select the explanation can be sought. At this point, the search for information is clearly focused and the questions should be closed rather than open-ended. With further evidence the RC should now be ready to select a working explanation to use in planning a corrective strategy. However, the RC should constantly monitor the system data that may necessitate a change in direction.

- **Planning Corrective Strategy:** When planning a corrective strategy, the RC should identify a workable solution, evaluate the potential consequences of the strategy, communicate the strategy, and plan for contingencies. The strategy should be one that responds to the cause of the problem as identified in the diagnosis. The selected strategy should meet two general guidelines. The strategy should respond to all the identified causes and minimize any potential adverse consequences. In many situations some trade-off of reliability versus economy is involved. In all cases, the RC should plan for contingencies both during and after implementation of the strategy. Once a strategy has been selected, all those involved in its implementation should be informed. All those involved in implementing the strategy and monitoring its effectiveness should be aware of the overall strategy and their role in it. If changes are made, they should also be clearly communicated to all those involved.

- **Implementation of Corrective Strategy:** Implementation of the strategy involves performing the required actions and monitoring the results. All steps of the strategy should be clearly communicated among the affected parties. Confirmation of the steps taken and corresponding results of this strategy should be provided to the RC by the CA(s). The RC should continuously remain alert for new data that may indicate the need for a shift in strategy.

- **After the Fact Analysis:** After the immediate problem has been resolved, the incident should be analyzed to determine whether appropriate actions were taken. After resolution, additional evidence may become available. Real time response to the event should be evaluated and appropriately documented.

Examples of Excellence

EOE-17

Reference — Section 5.1, Display Maintenance Tool
Submitted by — California Mexico Reliability Coordinator (CMRC)

Description

Tool/Practice Name:	Display Maintenance Tool Application
NERC Registration:	Reliability Coordinator

Overview

By using an equivalent display maintenance tool application, CMRC has taken a slightly different approach to ensure that its EMS displays are functioning properly (i.e., showing correct information, linked correctly) to maintain situational awareness for CMRC's operators.

All of CMRC's network application one-lines are derived from auto-generated simplified displays. Most external stations are left in the simplified form. Displays for internal stations are edited to include detailed switching and bus arrangement detail. Elements added to a display are automatically updated in the network model database using the display maintenance tool (through a visual display). This has prevented extended periods of downtimes for certain EMS failures.

Examples of Excellence

EOE-18
Reference — Section 5.2, Change Management Tools and Practices
Submitted by — PJM

Description

Tool/Practice Name: ChPro Change Management Tool

NERC Registration: Reliability Coordinator

Overview

RTBPTF notes that each entity has taken a slightly different approach to ensure that software modifications do not compromise the availability and integrity of critical real-time applications that support operator situational awareness. However, RTBPTF notes that PJM has a feature management system that resides only on their development environment. PJM also has a server identified as the source master server for that environment. Each code change that is made needs to be logged through the feature management system called "ChPro" on the development system. "ChPro" provides audit logging and version control capabilities. Once the code change is logged it can be moved to other environments for testing. Typically these changes are installed and tested on their process control test (PCT) environment, which receives real-time data from their production (PRD) environment to simulate results in the PRD environment. Once tested on the PCT environment, the feature must be logged in a change management system called REMEDY. These features need manager approval as well as operator notification and approval prior to being installed in the PRD environment unless the change is considered an emergency. Emergency changes can be installed immediately upon operator notification and approval to fix a problem. If the change is an emergency change, a REMEDY request must still be submitted for approval by a manager at a later time. Any change installed on the PRD environment is immediately re-tested to insure application integrity and availability. After the change is tested and approved on the PRD environment, it is moved to all other environments to insure synchronization of all systems. The PJM software maintenance tools and processes successfully comply with SAS 70 Type 2 audit standards.

Examples of Excellence

EOE-19
Reference — Section 5.3, Facilities Monitoring
Submitted by — American Electric Power (Central and Southwest)

Description

Tool/Practice Name:	Facilities Monitoring Application
NERC Registration:	Balancing Authority and Transmission Operator

Overview

Using equivalent facilities monitor applications, entities have taken slightly different approaches to ensure that critical equipment and facilities are functioning properly to maintain situational awareness for their operators. Central and Southwest (CSWS) interfaces its facilities monitoring application (called “Big Brother”) with its critical applications monitoring application. This interface provides CSWS with an extremely flexible tool for monitoring and notification (paging) for numerous aspects of it system.

Examples of Excellence

EOE-20
Reference — Section 5.4, Critical Applications Monitoring
Submitted by — Tennessee Valley Authority

Description

Tool/Practice Name:	Critical Applications Monitoring
NERC Registration:	Balancing Authority and Transmission Operator

Overview

Tennessee Valley Authority (TVA) uses a tool that monitors all critical and non-critical processes on their SCADA system. If a process fails, TVA's Network Operations Center can restart the process from a visual display. This has prevented extended downtimes during certain EMS failures.

Examples of Excellence

EOE-21

Reference — Section 5.4, Critical Applications Monitoring
Submitted by — International Transmission Company

Description

Tool/Practice Name: Critical Applications Monitoring

NERC Registration: Transmission Operator

Overview

International Transmission Company uses a tool that monitors the status of its state estimator and ICCP data applications. The tool generates text messages to a cell phone, which are automatically sent to an on-call operations engineer when the state estimator aborts and does not converge. When the data flow rate on the ICCP data links stalls, the tool sends text messages to a cell phone, which automatically goes to on-call IT support personnel and an on-call operations engineer.

Examples of Excellence

EOE-22
Reference — Section 5.4, Critical Applications Monitoring
Submitted by — American Transmission Company

Description

Tool/Practice Name: Critical Applications Monitoring

NERC Registration: Transmission Operator

Overview

American Transmission Company has created overview displays that not only show system performance but also EMS health checks. These overview displays allow the system operator to determine whether the EMS is operational and functioning properly. System operators are required to display these overview visuals and to notify the on-call EMS contact if a problem appears.

Examples of Excellence

EOE-23
Reference — Section 5.4, Critical Applications Monitoring
Submitted by — American Electric Power (Central and Southwest)

Description

Tool/Practice Name:	Critical Applications Monitoring
NERC Registration:	Transmission Operator

Overview

Central and Southwest (CSWS) interfaces its EMS Facilities Monitoring application (aptly called “Big Brother”) with its critical applications monitor. This interface is an extremely flexible tool for monitoring of and notification (paging) regarding numerous aspects of the CSWS system.

Examples of Excellence

EOE-24
Reference — Section 5.5, Trouble-Reporting Tool
Submitted by — Florida Power and Light

Description

Tool/Practice Name:	Trouble Report System
NERC Registration:	Transmission Operator and Balancing Authority

Overview

Florida Power and Light's (FPL) Trouble Report System (TRS) is a web-based application developed in house to facilitate logging, communication, and tracking of user problems with tools and systems maintained by the computer support group at FPL's System Control Center. Users are primarily operators. In addition to allowing entries of new trouble reports, the application performs administrative functions and can produce different query-based summary reports. The process flow and other functionalities are described below.

New Trouble Report Entry

Whenever a user encounters a problem with a tool or application, s/he can call computer support personnel or initiate a trouble report entry. Even if the user opts to call to report the problem, FPL considers it good practice to initiate a trouble report through TRS to ensure tracking. TRS also has an interface to FPL's e-mail system, so users can track trouble report status and eventual resolution. Trouble reports can be initiated by users or by support personnel that receive a call. When support personnel enter the report, they do so on behalf of the user reporting the problem. Once the user saves the entry, the trouble report status becomes PENDING.

Initial Evaluation

Support group personnel are assigned to periodically scan the TRS for reports with PENDING status and select the appropriate functional area to investigate and resolve each report. When the report is assigned, its status changes to ANALYZE, and an e-mail is automatically issued to the supervisor of the selected functional area notifying him/her of the new trouble report that has been assigned to his/her group.

If information provided by the user is insufficient for personnel to assign a report, the report status can be changed to MORE INFO, which automatically issues an e-mail to the user requesting more information. Once the user provides more information and saves the entry, the status returns to PENDING, and the process begins again.

Functional Area Process

The functional area supervisor, when notified by e-mail of a report, analyzes the problem. (The report can be accessed simply by clicking on the URL link provided in each e-mail issued by TRS.) The supervisor will then do one of the following:

- Assign the trouble report to appropriate personnel — This changes the status of the report to WORK ASSIGNED and generates an e-mail notifying both the staff member assigned to the report and the user that the report has been assigned. The supervisor determines the severity of the problem and assigns a priority to the report: high, medium, or low. The “Trouble Area” and “Application” fields of the report should also be filled in at this time. This information is useful for classifying problems in summary reports.
- Reassign the report to another functional area — The report status remains ANALYZE, and an e-mail is sent to the supervisor of the new functional area.
- Ask for more information regarding the problem — The supervisor can change the status of the report to MORE INFO, which generates an e-mail to the user requesting more information. Once the user provides more information and saves the entry, the status returns to ANALYZE, and an e-mail is issued to the functional area supervisor.

Trouble Resolution

The analyst assigned the trouble report reviews the severity of the problem and determines, based on workload, when to begin work on the problem. During the resolution stage, any of the following may occur:

- Problem is corrected — Once the analyst resolves the problem, s/he changes the report status to FIXED and describes the resolution. If the resolution requires code changes, the “Code Change Req” flag is selected, and modules that have been modified are specified in the resolution description. TRS automatically issues an e-mail to the user who reported the problem and to the functional area supervisor indicating that the problem has been fixed.
- No action could be taken to resolve the problem — This may be a result of an inability to duplicate the problem or determination that resolution of the problem would constitute a system enhancement, which requires that it go through a change management process. In this case, the analyst updates the status of the report to NO ACTION. TRS automatically issues an e-mail notifying the user who reported the problem and the functional area supervisor of the status change.
- Need more information from the user — The analyst can change the status of the report to MORE INFO. This generates an e-mail to the user requesting more information. Once the user provides more information and saves the entry, the status returns to WORK ASSIGNED, and an e-mail is sent to the analyst.

User Feedback

The user who initiated the report should verify that the problem has been corrected or agree that the problem is an enhancement that requires initiation of a change request. In both cases the user should update the status of the trouble report to CLOSED. If s/he disagrees with the resolution, a description of the disagreement is entered, and the status should be changed to NOT FIXED, which generates an e-mail back to the analyst.

Administrative Functions

TRS will e-mail weekly reports to each functional area supervisor listing all outstanding trouble reports assigned to their groups. These reports are copied to management. Outstanding trouble reports are those with a current status of ANALYZE, MORE INFO, WORK ASSIGNED, or NOT FIXED. TRS provides the following statistics on a per-trouble-report basis:

- Time elapsed from a report's first entry to the system to its assignment to a functional area
- Time elapsed from assignment to a functional area to assignment to an analyst
- Time elapsed from assignment to an analyst to resolution
- Total time spent on a trouble report (from initial entry to completion)
- Total number of times that a trouble report was returned by user as not fixed

Exhibit G-3

2011 Southwest Outage Report

Arizona-Southern California Outages on September 8, 2011

Causes and Recommendations

Prepared by the Staffs of the

Federal Energy Regulatory Commission
and the
North American Electric Reliability Corporation

April 2012

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

A. Synopsis of the Disturbance and System Recovery

On the afternoon of September 8, 2011, an 11-minute system disturbance occurred in the Pacific Southwest, leading to cascading outages and leaving approximately 2.7 million customers without power.[1] The outages affected parts of Arizona, Southern California, and Baja California, Mexico. All of the San Diego area lost power, with nearly one-and-a-half million customers losing power, some for up to 12 hours. The disturbance occurred near rush hour, on a business day, snarling traffic for hours. Schools and businesses closed, some flights and public transportation were disrupted, water and sewage pumping stations lost power, and beaches were closed due to sewage spills. Millions went without air conditioning on a hot day.

The loss of a single 500 kilovolt (kV)[2] transmission line initiated the event, but was not the sole cause of the widespread outages. The system is designed, and should be operated, to withstand the loss of a single line, even one as large as 500 kV. The affected line—Arizona Public Service's (APS) Hassayampa-N. Gila 500 kV line (H-NG)—is a segment of the Southwest Power Link (SWPL), a major transmission corridor that transports power in an east-west direction, from generators in Arizona, through the service territory of Imperial Irrigation District (IID), into the San Diego area. It had tripped on multiple occasions, as recently as July 7, 2011, without causing cascading outages.

With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the system, increasing flows through lower voltage systems to the north of the SWPL, as power continued to flow into San Diego on a hot day during hours of peak demand. Combined with lower than peak

[1] "Customers" are not the same as "people" in utility parlance. The term customer generally refers to a single meter, whether at a residence, an apartment building, or a factory. Thus, a single customer could represent one or more persons, and a single person could be two customers, for example, if the same utility served both an individual's residence and his small business. Estimates of "people" affected by blackouts generally are prepared by increasing the customer numbers by a multiplier, often two or three.

[2] A list of acronyms used in this report is included in Appendix A.

generation levels in San Diego and Mexico,[3] this instantaneous redistribution of power flows created sizeable voltage deviations and equipment overloads to the north of the SWPL. Significant overloading occurred on three of IID's 230/92 kV transformers located at the Coachella Valley (CV) and Ramon substations, as well as on Western Electricity Coordinating Council (WECC) Path 44,[4] located south of the San Onofre Nuclear Generating Station (SONGS) in Southern California.

The flow redistributions, voltage deviations, and resulting overloads had a ripple effect, as transformers, transmission lines, and generating units tripped offline, initiating automatic load shedding throughout the region in a relatively short time span. Just seconds before the blackout, Path 44 carried all flows into the San Diego area as well as parts of Arizona and Mexico. Eventually, the excessive loading on Path 44 initiated an intertie separation scheme at SONGS, designed to separate SDG&E from SCE. The SONGS separation scheme separated SDG&E from Path 44, led to the loss of the SONGS nuclear units, and eventually resulted in the complete blackout of San Diego and Comisión Federal de Electricidad's (CFE) Baja California Control Area. During the 11 minutes of the event, the WECC Reliability Coordinator (WECC RC) issued no directives and only limited mitigating actions were taken by the Transmission Operators (TOPs) of the affected areas.

As a result of the cascading outages stemming from this event, customers in the SDG&E, IID, APS, Western Area Power Administration-Lower Colorado (WALC), and CFE territories lost power, some for multiple hours extending into the next day. Specifically,

- SDG&E lost 4,293 Megawatts (MW) of firm load, affecting approximately 1.4 million customers.
- CFE lost 2,150 MW of net firm load, affecting approximately 1.1 million customers.[5]
- IID lost 929 MW of firm load, affecting approximately 146,000 customers.

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[3] Total summer peak generation for San Diego Gas and Electric's (SDG&E) territory and Comisión Federal de Electricidad's (CFE) Baja California Control Area is 5,774 MW. On September 8, 2011, the total generation for SDG&E and CFE's Baja California Control Area was 4,168, a difference of 1,606 MW.

[4] Path 44 is one of 81 Rated Paths in the WECC region. A Rated Path is composed of "an individual transmission line or a combination of parallel transmission lines." WECC 2011 Path Rating Catalog, January 2011, at item 1-i. Path 44, also referred to as "South of SONGS," is an aggregation of five 230 kV lines that delivers power in a north-south direction from the Southern California Edison (SCE) footprint in the Los Angeles area into the SDG&E footprint.

[5] CFE is Mexico's state-owned utility. Only its Baja California Control Area was affected on September 8, 2011. The inquiry is particularly grateful to CFE for its willingness to share data and information to assist the inquiry in developing the most accurate conclusions and recommendations.

- APS lost 389 MW of firm load, affecting approximately 70,000 customers.
- WALC lost 74 MW of firm load, 64 MW of which affected APS's customers. The remaining 10 MW affected 5 WALC customers.

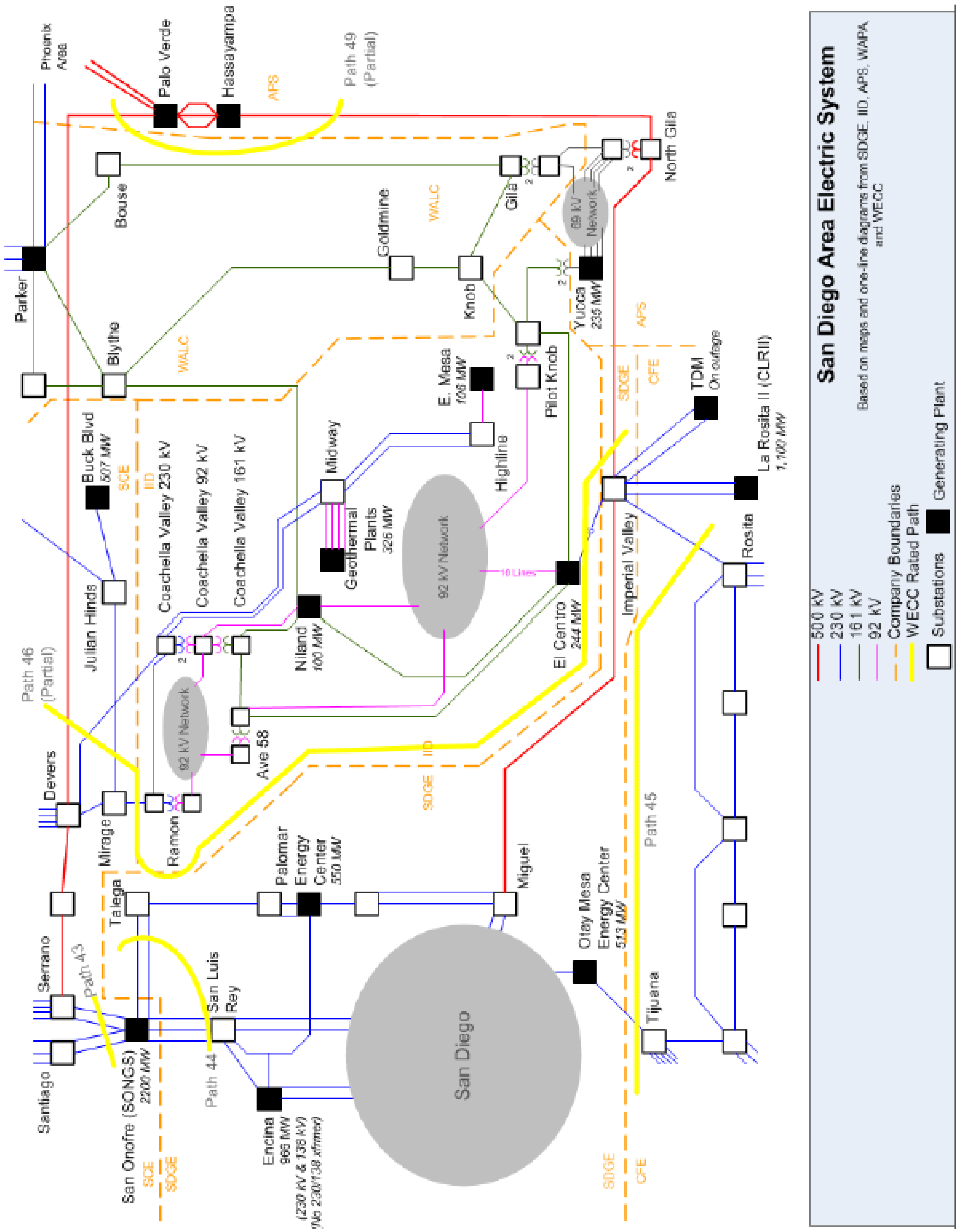
After the blackout, the affected entities promptly instituted their respective restoration processes.[6] All of the affected entities had access to power from their own or neighboring systems and, therefore, did not need to use "black start" plans.[7] Although there were some delays in the restoration process due to communication and coordination issues between entities, the process was generally effective. SDG&E took 12 hours to restore 100% of its load, and CFE took 10 hours to restore 100% of its load. IID, APS, and WALC restored power to 100% of their customers in approximately 6 hours. The affected entities also worked to restore generators and transmission lines that tripped during the event. IID and APS restored generation—333 MW for IID and 76 MW for APS—in 5 hours. Meanwhile, CFE restored 1,915 MW of tripped generation in 56 hours; SDG&E restored 2,229 MW of tripped generation in 39 hours; and SCE restored 2,428 MW of tripped generation in 87 hours. IID restored its 230 kV transmission system in 12 hours and its 161 kV system in 9 hours; APS restored H-NG in 2 hours; SDG&E restored its 230 kV system in 12 hours; WALC restored its 161 kV system in 1.5 hours; and CFE restored its 230 kV system in 13 hours and its 115 kV system in 10 hours.

B. Map of Affected Area and Key Facilities Involved in the Event

The following map, showing the areas affected by the September 8th event and the key facilities involved during the event, can be used as a reference throughout the report:

[6] The term "affected entities" in this report refers to TOPs and Balancing Authorities (BAs) that were affected by the event. The affected entities include SDG&E, IID, APS, WALC, SCE, CFE, and the California Independent System Operator (CAISO).

[7] Black start plans work to energize systems using internal generation to get from shutdown to operating condition without assistance from the Bulk Electric System (BES).


San Diego Area Electric System
Based on maps and one-line diagrams from SDGE, IID, APS, WAPA, and WECC
500 kV
230 kV
161 kV
92 kV
Company Boundaries
WECC Rated Path
Substations
Generating Plant
Phoenix Area
Palo Verde
Hassayampa
APS
Path 49 (Partial)
North Gila
Gila
Bouse
Parker
Goldmine
WALC
Knob
69 kV Network
Yucca 235 MW
Blythe
Pilot Knob
E. Mesa 106 MW
Highline
TDM On outage
La Rosita II (CLRII) 1,100 MW
Buck Blvd 507 MW
SCE
IID
Coachella Valley 230 kV
Coachella Valley 92 kV
Coachella Valley 161 kV
Midway
Geothermal Plants 326 MW
92 kV Network
10 Lines
El Centro 244 MW
Imperial Valley
SDGE
CFE
Rosita
Julian Hinds
Path 46 (Partial)
Niland 100 MW
Ave 58
Devers
Mirage
Ramon
Miguel
Path 45
Otay Mesa Energy Center 513 MW
Palomar Energy Center 550 MW
Talega
Serrano
Path 43
Santiago
San Onofre (SONGS) 2200 MW
San Luis Rey
Path 44
Encina 965 MW (230 kV & 138 kV) (No 230/138 xfrmer)
San Diego
Tijuana

C. Key Findings, Causes, and Recommendations[8]

The September 8, 2011, event showed that the system was not being operated in a secure N-1 state.[9] This failure stemmed primarily from weaknesses in two broad areas—operations planning and real-time situational awareness—which, if done properly, would have allowed system operators to proactively operate the system in a secure N-1 state during normal system conditions and to restore the system to a secure N-1 state as soon as possible, but no longer than 30 minutes. Without adequate planning and situational awareness, entities responsible for operating and overseeing the transmission system could not ensure reliable operations within System Operating Limits (SOLs) or prevent cascading outages in the event of a single contingency.[10] As demonstrated in Appendix C, inadequate situational awareness and planning were also identified as causes of the 2003 blackout that affected an estimated 50 million people in the United States and Canada.

The inquiry also identified other underlying factors that contributed to the event, including: (1) not identifying and studying the impact on Bulk-Power System (BPS)[11]

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[8] While this section highlights the most significant causes, findings, and recommendations, the report details the complete list of findings, causes, and recommendations in section IV. In addition, for ease of reference all of the findings and recommendations are summarized in table format in Appendix B.

[9] The North American Electric Reliability Corporation's (NERC) mandatory Reliability Standards applicable to the BES require that the BES be operated so that it generally remains in a reliable condition, without instability, uncontrolled separation or cascading, even with the occurrence of any single contingency, such as the loss of a generator, transformer, or transmission line. This is commonly known as the "N-1 criterion." N-1 contingency planning allows entities to identify potential N-1 contingencies before they occur and to adopt mitigating measures, as necessary, to prevent instability, uncontrolled separation, or cascading. As the Federal Energy Regulatory Commission (Commission) stated in Order No. 693 with regard to contingency planning, "a single contingency consists of a failure of a single element that faithfully duplicates what will happen in the actual system. Such an approach is necessary to ensure that planning will produce results that will enhance the reliability of that system. Thus, if the system is designed such that failure of a single element removes from service multiple elements in order to isolate the faulted element, then that is what should be simulated to assess system performance." *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1716 (2007), *order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

[10] A contingency is the unexpected failure of an electrical system component.

[11] The BPS is defined by Section 215(a) (1) of the Federal Power Act as "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability." The meaning of BPS and BES differ somewhat and, thus, this report uses each term in its proper context. With respect to reliability, the Commission has jurisdiction over all users, owners, and operators of the BPS. In Order No. 693 at P 75, the Commission adopted, at least for an initial period, the BES definition as the threshold for application of the NERC Reliability Standards. Thus, this report uses BES when referring to entities' specific facilities or elements that are subject to the Reliability Standards, but BPS when discussing the overall reliability impact. On January 25, 2012, NERC filed a petition with the Commission for approval of a revised definition of the BES. The proposed definition of BES would cover all elements operated at 100 kV or higher, with a list of specific inclusions and exclusions.

reliability of sub-100 kV facilities in planning and operations;[12] (2) the failure to recognize Interconnection Reliability Operating Limits (IROLs) in the Western Interconnection;[13] (3) not studying and coordinating the effect of protection systems, including Remedial Action Schemes (RASs), during plausible contingency scenarios;[14] and (4) not providing effective tools and operating instructions for use when reclosing lines with large phase angle differences across the reclosing breakers.[15]

With regard to operations planning, some of the affected entities' seasonal, next-day, and real-time studies do not adequately consider: (1) operations of facilities in external networks, including the status of transmission facilities, expected generation output, and load forecasts; (2) external contingencies that could impact their systems or internal contingencies that could impact their neighbors' systems; and (3) the impact on BPS reliability of internal and external sub-100 kV facilities. As a result, these entities' operations studies did not accurately predict the impact of the loss of APS's H-NG or the loss of IID's three 230/92 kV transformers. If the affected entities had more accurately predicted the impact of these losses prior to the event, these entities could have taken appropriate pre-contingency measures, such as dispatching additional generation to mitigate overloads and prevent cascading outages.

To improve operations planning in the WECC region, this report makes several recommendations designed to ensure that TOPs and BAs,[16] as appropriate: (1) obtain information on the operations of neighboring BAs and TOPs, including transmission outages, generation outages and schedules, load forecasts, and scheduled interchanges; (2) identify and plan for external contingencies that could impact their systems and

Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher are on the list of specific inclusions. *See North American Electric Reliability Corp.,* Docket No. RM12-6-000. This report takes no position on the petition.

[12] This report does not attempt to define the limits of which sub-100 kV facilities impact BPS reliability. Certainly, many facilities below 100 kV do not impact BPS reliability. The sub-100 kV facilities in this event affected the BPS because they were in parallel to significant transmission corridors.

[13] This report recommends that WECC RC should work with TOPs to consider whether any SOLs in the Western Interconnection constitute IROLs. As part of this effort, WECC RC should: (1) work with affected TOPs to consider whether Path 44 and H-NG should be recognized as IROLs; and (2) validate existing SOLs and ensure that they take into account all transmission and generation facilities and protection systems that impact BPS reliability.

[14] This failure caused the derived SOLs on H-NG and Path 44 to be invalid on the day of the event.

[15] As discussed in more detail in connection with Finding and Recommendation 27 below, when a line trips, the phase angle at one end of the line may be much larger than the phase angle at the other end. If the difference between the two angles is too great, reclosing the line could cause damage to generators or even system instability.

[16] See "Reliability Responsibilities" section at page 16 below.

internal contingencies that could impact their neighbors' systems; and (3) consider facilities operated at less than 100 kV that could impact BPS reliability. This effort should include a coordinated review of planning studies to ensure that operation of the affected Rated Paths will not result in the loss of non-consequential load, system instability, or cascading outages, with voltage and thermal limits within applicable ratings for N-1 contingencies originating from within or outside an entity's footprint.

The September 8th event also exposed entities' lack of adequate real-time situational awareness of conditions and contingencies throughout the Western Interconnection. For example, many entities' real-time tools, such as State Estimator and Real-Time Contingency Analysis (RTCA), are restricted by models that do not accurately or fully reflect facilities and operations of external systems to ensure operation of the BPS in a secure N-1 state. Also, some entities' real-time tools are not adequate or operational to alert operators to significant conditions or potential contingencies on their systems or neighboring systems. The lack of adequate situational awareness limits entities' ability to identify and plan for the next most critical contingency to prevent instability, uncontrolled separation, or cascading outages. If some of the affected entities had been aware of real-time external conditions and run (or reviewed) studies on the conditions prior to the onset of the event, they would have been better prepared for the impacts when the event started and may have avoided the cascading that occurred.

To improve situational awareness in the WECC region, this report makes several recommendations: (1) expand entities' external visibility in their models through, for example, more complete data sharing; (2) improve the use of real-time tools to ensure the constant monitoring of potential internal or external contingencies that could affect reliable operations; and (3) improve communications among entities to help maintain situational awareness. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS. These improvements will enable system operators to utilize real-time operating tools to proactively operate the system in a secure N-1 state.

In addition to the planning and situational awareness issues, several other factors contributed to the September 8th event. For example, WECC RC and affected entities do not consistently recognize the adverse impact that sub-100 kV facilities can have on BPS reliability. The prevailing SOLs should have included the effects of facilities that had not been identified and classified as part of the BES, as well as the effects of critical facilities such as Special Protection Systems (SPSs) and the SONGS separation scheme. Relevant to the event, these entities did not consider IID's 92 kV network and facilities, including the CV and Ramon 230/92 kV transformers, as part of the BES, despite some previous studies indicating their impact on the BPS due to the fact they were electrically in parallel with higher-voltage facilities.[17] If these facilities had been designated as part of the BES, or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems, the cascading outages may have been avoided. Accordingly, the inquiry makes a recommendation to ensure that facilities that can impact BPS reliability, regardless of voltage level, are considered for classification as part of the BES and/or studied as part of entities' planning in various time horizons.

The inquiry also found some significant issues with protection system settings and coordination. For example, IID used conservative overload relay trip settings on its CV transformers. The relays were set to trip at 127% of the transformers' normal rating, which is just above the transformers' emergency rating (110% of normal rating). Such a narrow margin between the emergency rating and overload trip setting resulted in the facilities being automatically removed from service without providing operators enough time to mitigate the overloads. As a result of these settings, both CV transformers tripped within 40 seconds of H-NG tripping, initiating cascading outages. To avoid a similar problem in the future, the inquiry recommends that IID and other Transmission Owners (TOs) review their transformers' overload protection relay settings. A good guideline for protective relay settings is Reliability Standard PRC-023-1 R1.11, which states that relays be "set to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater." TOPs should also plan to take proper pre-contingency mitigation measures with due consideration for the applicable emergency ratings and overload protection settings (MW and time delay) before a facility loads to its relay trip point and is automatically removed from service.

The SONGS separation scheme's operation provides another example of the lack of studies on, and coordination of, protection systems. This scheme, classified by SCE as a "Safety Net,"[18] had a significant impact on BPS reliability, separating SDG&E from SCE, resulting in the loss of both SONGS nuclear generators, and blacking out SDG&E

[17] *See, e.g.*, CFE's Path 45 Increase Rating Phase 2 Study Report, January 12, 2011, at 19.

[18] A Safety Net protection system protects the power system from unexpected, low-probability events that are outside the normal planning criteria, but which may lead to a complete system collapse. Safety Nets operate to minimize the severity of the event and attempt to prevent a system collapse or cascading outages. A Safety Net is typically intended to handle severe disturbances resulting from extreme, though perhaps not well-defined, events. A Safety Net is subject to review by the WECC Remedial Action Scheme Reliability Subcommittee if unintended operation would result in cascading or other performance standard violations. WECC Guideline: Remedial Action Scheme Classification, February 9, 2009.

and CFE. Nevertheless, none of the affected entities, including SCE, as the owner and operator of the scheme, studied its impact on BPS reliability. The September 8th event shows that all protection systems and separation schemes, including Safety Nets, RASs, and SPSs, should be studied and coordinated periodically to understand their impact on BPS reliability to ensure their operation, inadvertent operation, or misoperation does not have unintended or undesirable effects.

II. INTRODUCTION

A. Inquiry Process

On September 9, 2011, the Commission and NERC jointly announced an inquiry to determine the causes of the outages and make recommendations for preventing such events in the future. The purpose of the inquiry was not to determine whether there may have been violations of applicable regulations, requirements, or standards subject to the Commission's jurisdiction. Thus, while this report describes conduct which may warrant future investigations under Part 1b of the Commission's regulations,[19] or actions by NERC under its Compliance Monitoring and Enforcement Program,[20] it draws no conclusions about whether violations occurred.

The inquiry was composed of smaller teams with particular subject-matter expertise, primarily from Commission and NERC professional staff, each of which conducted rigorous analyses of a key issue or issues involved in the event. Those teams and their primary responsibilities were as follows:

- **Sequence of Events** – developed a precise and accurate sequence of events (SOE) to provide a foundation for root cause analysis, computer model simulations, and other analytical aspects of the inquiry.
- **System Modeling and Simulation** – developed an accurate system modeling case, benchmarked the case to actual conditions at critical times, replicated system conditions leading up to and during the outage, and simulated alternate "what if" scenarios.
- **Root Cause and Human Performance Analysis** – performed in a systematic evaluation of the root causes and contributing factors and identified areas requiring further inquiry.
- **Operations Tools, Supervisory Control and Data Acquisition (SCADA)/Energy Management System (EMS), Communications, and Operations Planning** – considered all aspects of the blackout related to operator and reliability coordinator knowledge of system conditions, actions or inactions, and communications, particularly the observability of the electric system and effectiveness of operational reliability assessment tools.
- **Frequency/Area Control Error (ACE) Analysis** – reviewed potential frequency anomalies related to the blackout, and analyzed underfrequency generator, load, and tie line tripping.

[19] 18 C.F.R. Part 1b (2011).

[20] NERC Compliance Monitoring and Enforcement Program, Appendix 4C to the NERC Rules of Procedure, January 31, 2012.

- **System Planning, Design, and Studies** – analyzed factors used in setting SOLs and actual limits in effect on the day of the blackout, determined whether those limits were exceeded, and analyzed the extent to which actual system conditions varied from the assumptions used in setting the SOLs.
- **Transmission and Generation Performance, Protection, Control, Maintenance, and Damage** – analyzed the causes of automatic facility operations and generator trips, analyzed transmission and generation facility maintenance practices, and identified equipment damage.
- **Restoration Review** – reviewed the appropriateness and effectiveness of the restoration plans implemented, as well as the effectiveness of the coordination of these plans among the affected entities and WECC RC.

Each team not only examined its own subject area to determine what may have contributed to the event, but also considered lessons learned and potential recommendations for preventing such events in the future.

The inquiry devoted substantial time and resources to determine and study the causes of the event and develop meaningful recommendations with the goal of preventing similar events in the future. The team's analyses were extensive, involving the review of high-quality data from various reliability entities in the WECC region and simulations of the event using sophisticated computer models. Described below in summary form are the primary steps the inquiry took to complete its analysis.

Data Gathering

The inquiry received and reviewed more than 20 gigabytes of data from approximately 500 data requests sent to entities in and around the affected areas. On September 19, 2011, the inquiry also began site visits with various entities involved in the outages, including entities with responsibility for balancing load and generation, transmission operation, and reliability coordination. During the site visits, the inquiry toured control centers, conducted dozens of interviews and depositions, and viewed equipment involved in the event. These visits and depositions allowed the inquiry to learn about control room operations and practices, system status and conditions on the day of the event, operating procedures, planning, operations, and real-time tools, and restoration planning and procedures. The inquiry also conducted dozens of follow-up meetings and issued follow-up data requests.

Of particular use to the inquiry were phasor measurement unit (PMU) records. PMUs are complex, multi-functional, high resolution recording devices installed widely throughout the Western Interconnection pursuant to a voluntary WECC-wide initiative. PMUs provide continuous, high-speed (30 scans per second) records of system conditions, including frequency, voltage, and phase angle relations. The continuous nature of the data available through the PMUs, as well as their wide distribution throughout the power system, proved especially valuable to the inquiry in forming an accurate picture of the SOE and state of the system at particular points in time throughout the disturbance.

SOE Methodology

More than 100 notable events occurred in less than 11 minutes on September 8, 2011. The inquiry's SOE team established a precise and accurate sequence of outage-related events to form a critical building block for the other parts of the inquiry. It provided, for example, a foundation for the root cause analysis, computer-based simulations, and other event analyses. Although entities time-stamp much of the data related to specific events, their time-stamping methodologies vary, and not all of the time-stamps were synchronized to the National Institute of Standards and Technology (NIST) standard clock in Boulder, Colorado. Validating the precise timing of specific events became a time-consuming, important, and sometimes difficult task. The availability of global positioning system (GPS)-time synchronized PMU data on frequency, voltage, and related power angles made this task much easier than in previous blackout inquiries and investigations.

To develop the SOE, the SOE team started by resolving discrepancies between the multiple sources of data, sign convention inconsistencies, and incorrect data. The SOE team then developed an events database starting with all known events and times. Initial sources for the development of the database included preliminary reports filed by the affected entities as well as initial responses to data requests. The team then examined each record in the database to verify event times using available SCADA and PMU data. As the frequency, line flow, or voltage data suggested that additional events might have occurred on the system, the team added other possible events and verified them through additional data requests.

The SOE team developed multiple iterations of an SOE narrative document based on the database and the available SCADA and PMU data. Some iterations of the SOE narrative required that more data be requested of affected entities, and ultimately multiple data requests were sent to each entity. After the team completed the SOE narrative, the inquiry's Modeling and Simulation team verified the SOE using power flow, voltage stability, and dynamic stability analyses.

Power Flow and Dynamics Analysis

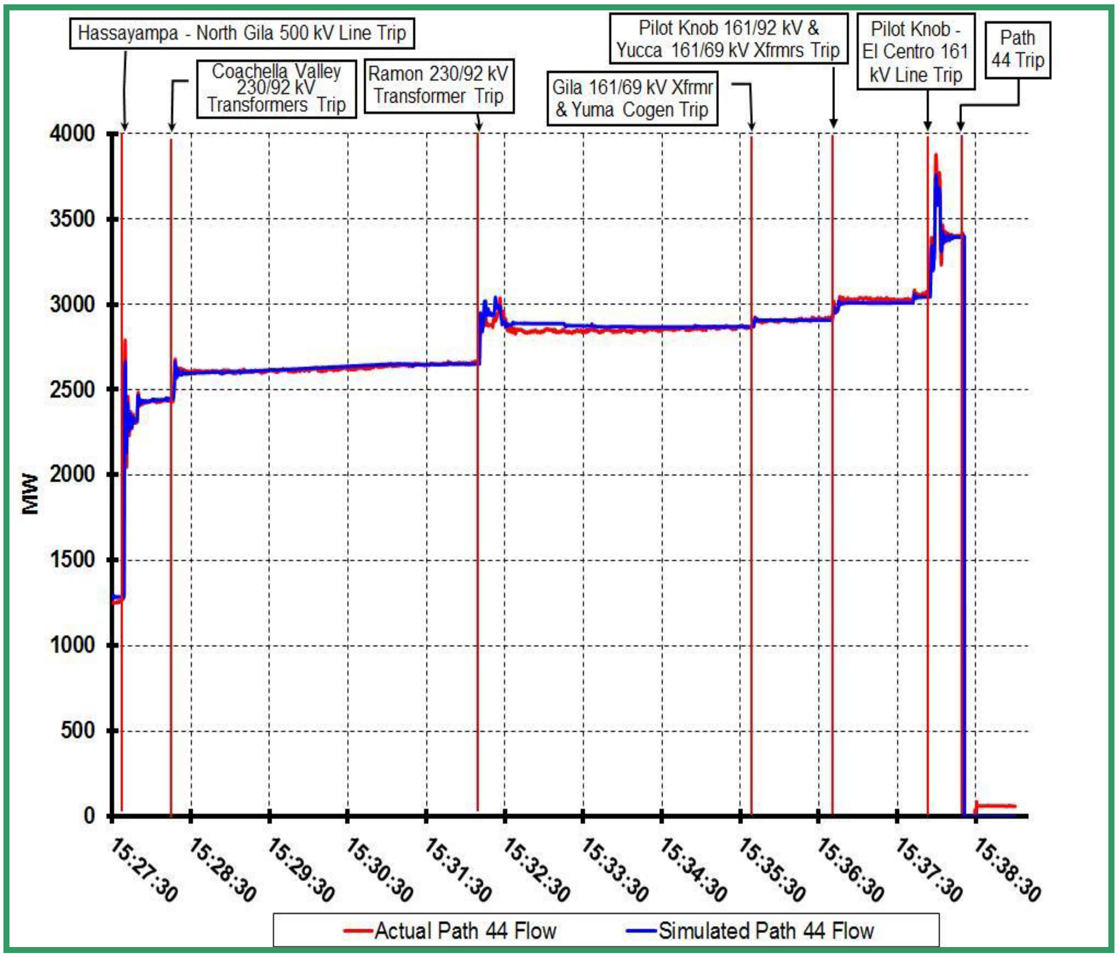
The inquiry's Modeling and Simulation team, after validating the SOE, considered several "what if" scenarios. The Modeling and Simulation team's work is described in more detail in Appendix D. Power flow analyses study power systems under quasi-steady-state conditions by matching load and generation to obtain voltage magnitude and angle at each bus and the real and reactive power flowing through each transmission facility. Dynamic stability analyses study the impact of disturbances on frequency, voltage, and rotor angle stability, and determine whether transients in the power system are stable, thus allowing the power system to return to a quasi-steady-state operating condition following a disturbance.[21]

As the first step in performing power flow and dynamic stability analyses, the Modeling and Simulation team developed and benchmarked a modeling case of system conditions prior to the event. The team started with the WECC heavy summer base case and made adjustments based on State Estimator snapshots, EMS data, actual generation and schedules, PMU data, and a base case prepared by a separate team (led by CAISO) that studied the event. The team further adjusted and benchmarked the base case using SCADA and PMU data to match the system conditions for the entire event. The team devoted considerable time and effort to resolving discrepancies between the various sources of data to best calibrate the modeling case to actual measured data. As illustrated by ***Figure* 1**, on the next page, and described in more detail in Appendix D, the Modeling and Simulation team achieved a significant degree of accuracy. This figure compares Path 44 flows simulated by the Modeling and Simulation team to actual Path 44 PMU data.

After developing and benchmarking a valid case, the Modeling and Simulation team simulated the entire SOE using both power flow and dynamic simulations. This replication of the SOE established the validity of the model and enabled meaningful simulation of several alternative scenarios, developed to answer "what if" questions regarding the event. For example, the inquiry considered what would have happened if some of the affected entities had dispatched generation at certain locations during the event, if overload relays had been set at different levels, or if RASs, Safety Nets, or other SPSs had been designed or operated differently.

[21] Transient stability refers to the ability of synchronous generators to move to a new quasi-steady-state operating point while remaining synchronized after the system experiences a disturbance.

Figure 1: Comparison of Actual and Simulated Path 44 Flows



Outreach Sessions

After developing a list of preliminary findings and recommendations, the inquiry conducted outreach meetings with various industry associations and groups, including CAISO, WECC, the American Public Power Association (APPA), the North American Transmission Forum (NATF), the Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), and representatives from Regional Entities (REs), Regional Transmission Organizations, and Independent System Operators. Team members shared the inquiry's preliminary findings and recommendations on a non-public basis with members of these organizations to obtain feedback and, with respect to the recommendations, input as to their practicality and feasibility. The inquiry considered the feedback and input provided by these organizations and incorporated much of it into the findings and recommendations included in this report.

B. System Overview

This subsection provides an overview of: (1) the Western Interconnection and its position in the North American electric grid; (2) the reliability entities responsible for operating the grid; (3) a description of the affected entities; and (4) a discussion of the interconnected nature of these entities.

The Western Interconnection and Its Position in the North American Electric Grid

NERC shares its mission of ensuring the reliability of the BPS in North America with eight REs through a series of delegation of authority agreements. WECC is the designated RE responsible for coordinating and promoting BPS reliability in the Western Interconnection. In its capacity as the RE, WECC monitors and enforces compliance with Reliability Standards by the users, owners, and operators of the BPS. WECC also functions as an Interconnection-wide planning facilitator, aiding in transmission and resource integration planning at the request of its members, as well as a provider of data, analysis, and studies related to transmission planning and reliability issues.

The WECC region extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, the states of Washington, Oregon, California, Idaho, Nevada, Utah, Arizona, Colorado, Wyoming, and portions of Montana, South Dakota, New Mexico, and Texas. See ***Figure*** **2**, on the next page. The WECC region is nearly 1.8 million square miles in size, has over 126,000 miles of transmission, and serves a population of 78 million. WECC contains 37 BAs and 53 TOPs. Due to the diverse characteristics of this extensive region, WECC encounters unique challenges in day-to-day coordination of its interconnected system. WECC is tied to the Eastern Interconnection through a number of high-voltage direct current transmission ties.

WECC also operates two RC offices that provide situational awareness and real-time monitoring of the entire Western Interconnection. WECC RC was an affected entity, and will be discussed with other affected entities below.

Figure 2: Map of WECC Region

Reliability Responsibilities

NERC categorizes the entities responsible for planning and operating the BPS in a reliable manner into multiple functional entity types. The NERC functional entity types most relevant to this event are BAs, TOs, TOPs, Generator Operators (GOPs), Planning Coordinators (PCs), Transmission Planners (TPs), and RCs. These functions are described in more detail in NERC's Reliability Functional Model.[22] Some of the affected entities conduct multiple reliability functions.

- ### Balancing Authority

The BA integrates resource plans ahead of time, maintains in real time the balance of electricity resources (generation and interchange) and electricity demand or load within its footprint, and supports the Interconnection frequency in real time. There

[22] NERC Reliability Functional Model, Version 5, http://www.nerc.com/files/Functional_Model_V5_Final_2009Dec1.pdf.

are 37 BAs in the WECC footprint. The following five BAs were affected by the event: APS, IID, WALC, CAISO, and CFE.

- **Transmission Owner, Transmission Operator and Generator Operator**

The TO owns and maintains transmission facilities. The TOP is responsible for the real-time operation of the transmission assets under its purview. The TOP has the authority to take corrective actions to ensure that its area operates reliably. The TOP performs reliability analyses, including seasonal and next-day planning and RTCA, and coordinates its analyses and operations with neighboring BAs and TOPs to achieve reliable operations. It also develops contingency plans, operates within established SOLs, and monitors operations of the transmission facilities within its area. There are 53 TOPs in the WECC region. The following seven TOPs were affected by the event: APS, IID, WALC, CAISO, CFE, SDG&E, and SCE. The GOP operates generating unit(s) and performs the functions of supplying energy and other services required to support reliable system operations, such as providing regulation and reserve capacity.

- **Planning Coordinator**

The PC is responsible for coordinating and integrating transmission facility and service plans, resource plans, and protection systems.[23]

- **Transmission Planner**

The TP is responsible for developing a long-term (generally one year and beyond) plan for the reliability of the interconnected bulk transmission systems within its portion of the Planning Coordinator Area.

- **Reliability Coordinator**

The RC and TOP have similar roles, but different scopes. The TOP directly maintains reliability for its own defined area. The RC is the "highest level of authority" according to NERC, and maintains reliability for the Interconnection as a whole. Thus, the RC is expected to have a "wide-area" view of the entire Interconnection, beyond what any single TOP could observe, to ensure operation within IROLs.

The RC oversees both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure reliable

[23] PCs are the same as Planning Authorities (PAs) with respect to NERC registration and the Reliability Standards.

operation. The RC, for example, may direct a TOP to take whatever action is necessary to ensure that IROLs are not exceeded.[24] The RC performs reliability analyses including next-day planning and RTCA for the Interconnection, but these studies are not intended to substitute for TOPs' studies of their own areas. Other responsibilities of the RC include responding to requests from TOPs to assist in mitigating equipment overloads. The RC also coordinates with TOPs on system restoration plans, contingency plans, and reliability-related services.

Descriptions of Affected Entities

The following entities were affected by the September 8th event:

- ### WECC RC

In its capacity as the RC, WECC is the highest level of authority responsible for the reliable operation of the BPS in the Western Interconnection. WECC RC oversees the operation of the Western Interconnection in real time, receiving data from entities throughout the entire Interconnection, and providing high-level situational awareness for the entire system. WECC RC can direct the entities it oversees to take certain actions in order to preserve system reliability. Although WECC is both an RE and an RC, these two functions are organizationally separated.

- ### Imperial Irrigation District

IID, which encompasses the Imperial Valley, the eastern part of Coachella Valley in Riverside County, and a small portion of San Diego County, in California, owns and operates generation, transmission, and distribution facilities in its service area to provide comprehensive electric service to its customers. Thus, IID is a vertically integrated utility. IID's generation consists of hydroelectric units on the All-American Canal as well as oil-, nuclear-, coal-, and gas-fired generation facilities, with a total net capability of 514 MW. IID purchases power from other electric utilities to meet its peak demands in summer, which can exceed 990 MW. IID's transmission system consists of approximately 1,400 miles of 500, 230, 161, and 92 kV lines, as well as 26 transmission substations. Among other NERC registrations, IID is a TOP, BA, and TP responsible for

[24] For example, IRO-005-1 R.5 requires that "[e]ach [RC] shall identify the cause of any potential or actual SOL or IROL violations. The [RC] shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The [RC] shall be able to utilize all resources, including load shedding, to address an IROL violation."

resource and transmission planning, load balancing, and frequency support for its footprint.

- **Arizona Public Service**

APS is a vertically integrated utility that serves a 50,000 square mile territory spanning 11 of Arizona's 15 counties. Among other NERC registrations, APS is the TOP and BA for its territory. APS engages in both marketing and grid operation functions, which are separated. APS owns and operates transmission facilities at the 500 (including H-NG), 345, 230, 115, and 69 kV levels, and owns approximately 6,300 MW of installed generation capacity. APS's 2011 peak load was 7,087 MW.

- **Western Area Power Administration – Lower Colorado**

WALC is one of the four entities constituting the Western Area Power Administration, a federal power marketer within the United States Department of Energy. WALC operates in Arizona, Southern California, Colorado, Utah, New Mexico, and Nevada, and is registered with NERC as a BA, TOP, and PC for its footprint. As a net exporter of energy, WALC's territory has over 6,200 MW of generation, serving at most 2,100 MW of peak load. A majority of WALC's generation is federal hydroelectric facilities, with the balance consisting of thermal generation owned and operated by independent power producers. WALC also operates an extensive transmission network within its footprint, and is interconnected with APS, SCE, and nine other balancing areas.

- **San Onofre Nuclear Generating Station**

SONGS is a two-unit nuclear generation facility capable of producing approximately 2,200 MW of power, and is located north of San Diego.[25] SONGS produces approximately 19% of the power used by SCE customers and 25% of the power used by SDG&E customers. SONGS is jointly owned by SCE (78.21%), SDG&E (20%), and the City of Riverside (1.79%). SCE, as TO and GO, is responsible for ensuring the safe and reliable operation of SONGS within the grid.

- **California Independent System Operator**

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[25] SONGS is currently in the midst of an extended outage. According to a March 2012 press release by CAISO, if both SONGS units remain offline for the summer, "San Diego and portions of the Los Angeles Basin may face local reliability challenges." http://www.caiso.com/Documents/SummerGridOutlook Complicated-PossibleExtendedOutage-NuclearPowerPlant.pdf.

CAISO runs the primary market for wholesale electric power and open-access transmission in California, and manages the high-voltage transmission lines that make up approximately 80% of California's power grid. CAISO operates its market through day-ahead and hour-ahead markets, as well as scheduling power in real time as necessary. Among other registrations, CAISO is PC and BA for most of California, including the city of San Diego. It also acts as TOP for several entities within its footprint, including SDG&E and SCE. CAISO likewise engages in modeling and planning functions in order to ensure long-term grid reliability, as well as identifying infrastructure upgrades necessary for grid function.

- **San Diego Gas and Electric**

SDG&E is a utility that serves both electricity and natural gas to its customers in San Diego County and a portion of southern Orange County, and is the primary utility for the city of San Diego. SDG&E owns relatively little generation—approximately 600 MW—although generation owned by others in its footprint brings the total generation capacity of the area above 3,350 MW. Peak load for the area can exceed 4,500 MW in the summer. SDG&E also operates an extensive high-voltage transmission network at the 500, 230, and 138 kV levels. SDG&E, operating as a TOP within CAISO's BA footprint, has delegated part of its responsibilities as a TOP to CAISO.

- **Comisión Federal de Electricidad – Baja California Control Area**

CFE is the only electric utility in Mexico, servicing up to 98% of the total population. CFE's Baja California Control Area is not connected to the rest of Mexico's electric grid but is connected to the Western Interconnection. CFE's Baja California Control Area covers the northwest corner of Mexico, including the cities of Tijuana, Rosarito, Tecate, Ensenada, Mexicali, and San Luis Rio Colorado. CFE's Baja California Control Area operates transmission systems at the 230, 161, 115, and 69 kV levels, and owns 2,039 MW of gross generating capacity and the rights to a 489 MW independent power producer within the Baja California Control Area. CFE's Baja California Control Area had a net peak load of 2,184 MW for summer 2010. CFE's Baja California Control Area is connected at the 230 kV level with SDG&E through two transmission lines on WECC Path 45. CFE functions as the TO, TOP, and BA for its Baja California Control Area under the oversight of WECC RC. For the remainder of this report, "CFE" refers only to its Baja California Control Area.

- **Southern California Edison**

SCE is a large investor-owned utility which provides electricity in central, coastal, and southern California. SCE is a wholly-owned subsidiary of Edison International, which is also based in California. Among other NERC registrations, SCE operates as a TOP within CAISO's BA footprint, and has delegated part of its responsibilities as a TOP to CAISO. SCE is also registered as TP, and is responsible for the reliability assessments of the SONGS separation scheme. SCE owns 5,490 circuit miles of transmission lines, including 500, 230, and 161 kV lines. SCE also operates a subtransmission system of 7,079 circuit miles at the 115, 66, 55, and 33 kV levels. Of the affected entities, SCE is interconnected with APS, IID, and SDG&E at various transmission voltage levels. SCE owns over 5,600 MW of generation, including a majority share in SONGS, and its peak load exceeds 22,000 MW. Along with SONGS staff, SCE is responsible for the safe and reliable operation of the nuclear facility.

Interconnected Operations

The September 8th event exemplifies the interconnected operations of three parallel transmission corridors through which power flows into the area where the blackout occurred. Typically, BAs, through dispatch, balance the flows on these corridors so that no one corridor experiences overloads in an N-1 situation, but this did not happen on September 8th.

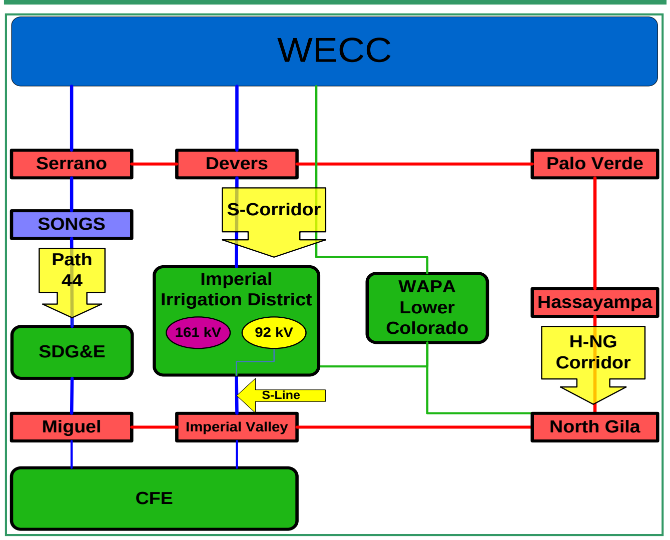
The first transmission corridor consists of the 500 kV H-NG, which is one of several transmission lines forming Path 49 ("East of River"). Along with two 500 kV lines, one from North Gila to Imperial Valley and another from Imperial Valley to Miguel, they form the SWPL. The majority of the SWPL is geographically parallel to the United States-Mexico border. The SWPL meets the SDG&E and IID systems at the Imperial Valley substation. This is shown as the "H-NG Corridor" on ***Figure 3***, on the next page.

The second corridor is Path 44, also known as "South of SONGS," operated by CAISO. This corridor includes the five 230 kV lines in the northernmost part of the SDG&E system that connect SDG&E with SCE at SONGS.

The third transmission corridor, shown as the "S Corridor" on Figure 3, consists of lower voltage (230, 161 and 92 kV) facilities operated by IID and WALC in parallel with those of SCE, SDG&E, and APS. The only major interconnection between IID and SDG&E is through the 230 kV "S" Line, which connects the SDG&E/IID jointly-owned Imperial Valley Substation (operated by SDG&E) to IID's El Centro Switching Station. The S Line interconnects the southern IID system with SDG&E and APS at Imperial Valley, which is also a terminus for the SWPL segment from Miguel and the SWPL segment from North Gila. WALC is connected to the SCE system and the rest of the Western Interconnection by 161 kV ties at Blythe, to IID by the 161 kV tie between WALC's Knob and IID's Pilot Knob substations, and to APS by a 69 kV tie via Gila at North Gila.

The eastern end of the SWPL, which terminates at APS's Hassayampa hub, is connected to SCE via a 500 kV line that connects APS's Palo Verde and SCE's Devers substations. The northern IID system is connected to SCE's Devers substation via a 230 kV transmission line that connects from Devers to IID's CV substation. These connections, along with SDG&E's connection to SCE via Path 44's terminus at SONGS, make the SWPL, Path 44, and IID's and WALC's systems operate as electrically parallel transmission corridors.[26] The following simplified diagram illustrates the interconnected nature of these three parallel corridors. Red lines represent 500 kV, blue lines represent 230 kV, and green lines represent 161 kV.

Figure 3: Three Parallel Corridors



[26] Power transfers from APS to SDG&E and CFE generally flow across the SWPL, but, due to parallel path flows, also known as loop flows, some of the power transfers flow through IID's and WALC's systems. Loop flow refers to power flow along any transmission paths that are in parallel with the most direct geographic or contract path.

III. SEQUENCE OF EVENTS[27]

The 11 minutes of the disturbance are divided into seven phases, as highlighted in ***Figure* 4**, on the next page. This figure displays the progressive loading of the five 230 kV tie lines from SCE north of San Diego that form Path 44. This section describes how the loss of various elements during an 11-minute period combined to exceed the 8,000 amp setting on the SONGS separation scheme. After sustained loading on Path 44 above 8,000 amps, the SONGS separation scheme operated. Once the SONGS separation scheme operated, San Diego and IID, CFE, and Yuma, Arizona, blacked out in less than 30 seconds. This section is divided into subsections for each phase, including the key events during the phase, their causes and effects, and, where relevant, what the affected entities knew and did not know as the events were unfolding. Each section begins with a brief summary. A final subsection describes restoration efforts after the blackout.

A set of graphics is included at the end of each phase to demonstrate the effect of the events during the phase. The first graphic in each set depicts the aggregate loading in amps on the five South of SONGS lines.[28] The bottom portion of the graphic shows all of the phases, while the majority of the graphic shows an expanded view of the phase being discussed. The second graphic in each set represents the loading on key facilities after each phase. The third graphic in each set shows how power flows redistributed through Arizona, Southern California, and Mexico after each phase. Phases 6 and 7 have multiple power flow graphics. Phases 1 and 7 include only the second and third type of graphics.

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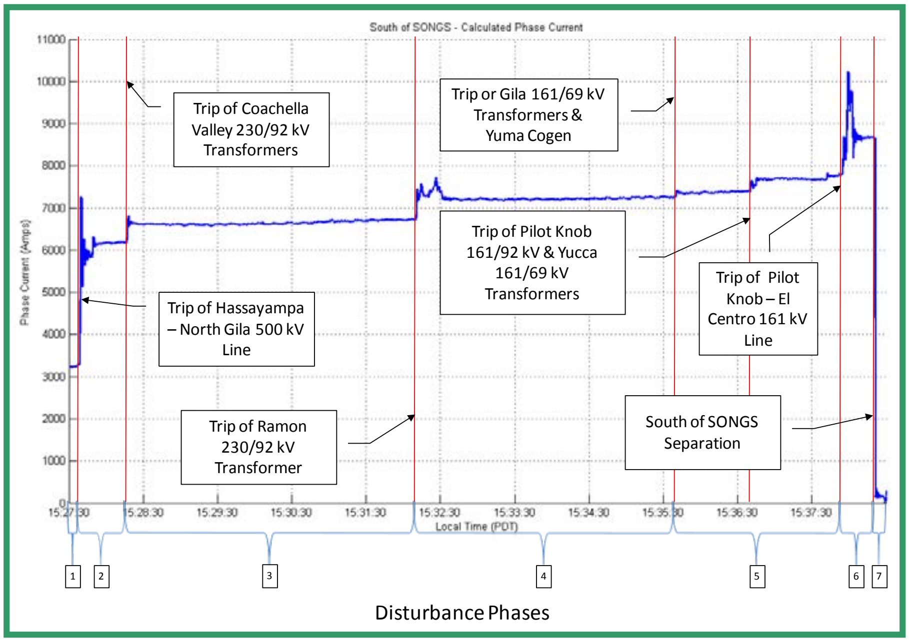
27 All times are in Pacific Daylight Time (PDT) unless otherwise noted. Times are listed to millisecond (three decimal places) or tenth-of-second (decimal place) accuracy when possible. If milliseconds or tenth-of-seconds are not listed, the event is reconciled to the nearest second.

28 Path 44 flows (complex power in volt amperes, current in amps) were calculated from SONGS PMU data. Those readings differ somewhat from disturbance monitoring equipment that was unavailable until completion of the inquiry's analysis. The differences are explained by variances in how some minor auxiliary loads are measured and in measurement equipment tolerances.

The following figure shows all seven phases of the disturbance.

Figure 4: Seven Phases of the Disturbance



A. Phase 1: Pre-Disturbance Conditions

Phase 1 Summary:

- Timing: September 8, 2011, before H-NG trips at 15:27:39
- A hot, shoulder season day with some generation and transmission maintenance outages
- Relatively high loading on some key facilities: H-NG at 78% of its normal rating, CV transformers at 83%
- 44 minutes before loss of H-NG, IID's RTCA results showed that the N-1 contingency loss of the first CV transformer would result in an overload of the second transformer above its trip point
- An APS technician skipped a critical step in isolating the series capacitor bank at the North Gila substation

September 8, 2011, was a relatively normal, hot day in Arizona, Southern California, and Baja California, Mexico, with heavy power imports into Southern California from Arizona. In fact, imports into Southern California were approximately 2,750 MW, just below the import limit of 2,850 MW. September is generally considered a "shoulder" season, when demand is lower than peak seasons and generation and transmission maintenance outages are scheduled. By September 8th, entities throughout the WECC region, including some of the affected entities, had begun generation and transmission outages for maintenance purposes. For example, on September 8th maintenance outages included over 600 MW of generation in Baja California.[29] and two 230 kV transmission lines in SDG&E's territory. However, there were no major forced outages or major planned transmission outages that would result in a reduction of the SOLs in the area.

- **Pre-Disturbance Conditions in IID**

Despite September being considered a shoulder month, temperatures in IID's service territory reached 115 degrees on September 8th.[30] IID's load headed toward near-peak levels of more than 900 MW, which required it to dispatch local combustion turbine generation in accordance with established operating procedures. Prior to the event, loading on IID's CV transformers reached approximately 125 megavolt amperes (MVA) per transformer, which is approximately 83% of the transformers' normal limit. Loading on IID's Ramon transformer was 153 MVA, which is approximately 68% of its normal limit.

IID's S Line ties IID to SDG&E, and through SDG&E, to generation in Mexico at La Rosita. It also ties CFE and IID, through SDG&E's La Rosita international transmission line. Before the event, IID was importing power on the S Line, and thus power was flowing northward from the jointly owned Imperial Valley substation to IID's El Centro substation. Flows on the S Line would reverse multiple times during the event. When power flowed on the S Line from south to north, the implication was that IID was supplied radially through SDG&E. Throughout the event, as power flowed from north to south, the implication was that flows intended for SDG&E and/or CFE were moving through IID's system. Eventually, in Phase 6, south to north flows on the S Line would activate a RAS that would ultimately trip more than 400 MW of generation at La Rosita and the S Line, thereby worsening the loading on Path 44.

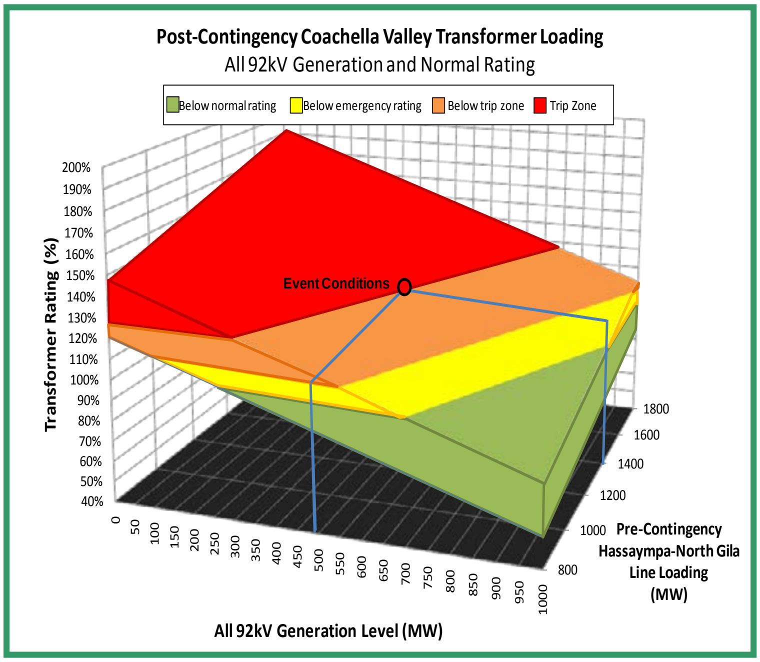
Forty-four minutes prior to the loss of H-NG on September 8, 2011, IID's RTCA results showed that the N-1 contingency loss of the first CV transformer would result in an overload of the second transformer above its trip point. The IID operator was not actively monitoring the RTCA results and, therefore, was not alerted to the need to take any corrective actions. At the time of the event, IID operators did not keep the RTCA

[29] The generation was known as Termoelectrica de Mexicali, and will be hereafter referred to as "TDM." It is also shown as "TDM" on the Map of Affected Entities.

[30] According to IID, the temperature in El Centro, California reached 115 degrees on September 8, 2011.

display visible, and RTCA alarms were not audible. By reducing loading on the CV transformers at this pre-event stage, the operator could have mitigated the severe effects on the transformers that resulted when H-NG tripped. Since the event, IID has required, and now requires, its operators to have RTCA results displayed at all times. The loading on IID's CV transformers was pivotal to this event. Loading on the CV transformers is influenced by: (1) the pre-contingency flow on H-NG; (2) load and generation in IID's 92 kV network; (3) flow on the S Line; and (4) to a lesser extent, generation connected to the Imperial Valley substation. See Figure 5, below.

Figure 5: Post-Contingency CV Transformer Loading Based on All IID 92 kV Generation



▪ Pre-Disturbance Conditions in CFE

At 15:07 CFE's Presidente Juarez Unit 11 tripped, which required CFE to activate its Baja California Control Area contingency reserves to restore its ACE. At 15:15 PDT CFE returned its ACE to where it had been before the unit tripped. Although still complying with the spinning reserve requirements, CFE was short on non-spinning reserve, with all of its available resources in use or already deployed.

- ### Pre-Disturbance Focus of WECC RC

Prior to the event, WECC RC operators were monitoring unscheduled flow on several paths in Northern California. WECC RC did not view any of the scheduled transmission or generation outages as significant. As illustrated by the chart below, two minutes before the event (at 15:25), major paths in the blackout area were operating below their Path ratings:

Major Paths in the Blackout Area	Established Path Ratings/Flow Limits	Path Loadings in MW and %
500 kV H-NG (Part of Corridor 1 into blackout area)	1,800 MW.[31]	1,397 MW 78%
Path 44 (Corridor 2 into blackout area)	2,200 MW.[32]	1,302 MW 59%
230 kV S Line (Part of Corridor 3 into blackout area)	239 MW	90 MW 38%
SDG&E Import SOL	2,850 MW	2,539 MW 89%
SDG&E to CFE Path 45	800 MW S-N; 408 MW N-S	241 MW N-S 60%

- ### Pre-Disturbance Conditions in APS

APS manages H-NG, a segment of the SWPL. At 13:57:46, the series capacitors.[33] at APS's North Gila substation were automatically bypassed due to phase imbalance protection. APS sent a substation technician to perform switching to isolate the capacitor bank. The technician was experienced in switching capacitor banks, having performed switching approximately a dozen times. APS also had a written switching order for the specific H-NG series capacitor bank at North Gila. After the APS system operator and the technician verified that they were working from the same switching order, the operator read steps 6 through 16 of the switching order to the technician. The technician repeated each step after the operator read it, and the operator verified the

[31] The limit of H-NG is a portion of the rating of Path 49. The inquiry determined that the limit is approximately 1,800 MW.

[32] With one segment of the SWPL out, the limit increases to 2,500 MW.

[33] A series capacitor is a power system device that is connected in series with a transmission line. It increases the transfer capability of the line by reducing the voltage drop across the line and by increasing the reactive power injection into the line to compensate for the reactive power consumption. In simple terms, a 50% series compensated line means it has the equivalent of 50% of the electric distance (or impedance) of the otherwise uncompensated line.

technician had correctly understood the step. The technician then put a hash mark beside each of steps 6 through 16 to indicate that he was to perform those steps. The technician did not begin to perform any of steps 6 through 16 until after all steps had been verified with the system operator.

The technician successfully performed step 6, verifying that the capacitor breaker was closed, placing it in "local" and tagging it out with "do not operate" tags. However, because he was preoccupied with obtaining assistance from a maintenance crew to hang grounds[34] for a later step, he accidentally wrote the time that he had completed step 6 on the line for step 8. For several minutes, he had multiple conversations about obtaining assistance to hang the grounds. He then looked back at the switching order to see what step should be performed next. His mistake in writing the time for step 6 on the line for step 8 caused him to pick up with step 9, rather than step 7.[35] Thus, he skipped two steps, one of them the crucial step (step 8) of closing a line switch to place H-NG in parallel with the series capacitor bank. This step would bypass the capacitor bank, resulting in almost zero voltage across the bank and virtually zero current through the bank. Because he skipped step 8, when he began to crank open the hand-operated disconnect switch to isolate the capacitor bank, it began arcing under load.[36] He could not manage to toggle the gearing on the switch to enable its closure, so he stayed under the arcing 500 kV line, determined to crank open the switch far enough to break the arc, thereby preventing additional damage to the equipment. ***Figure* 6**, on the next page, is a schematic of the APS series capacitor bank, showing steps seven through nine.

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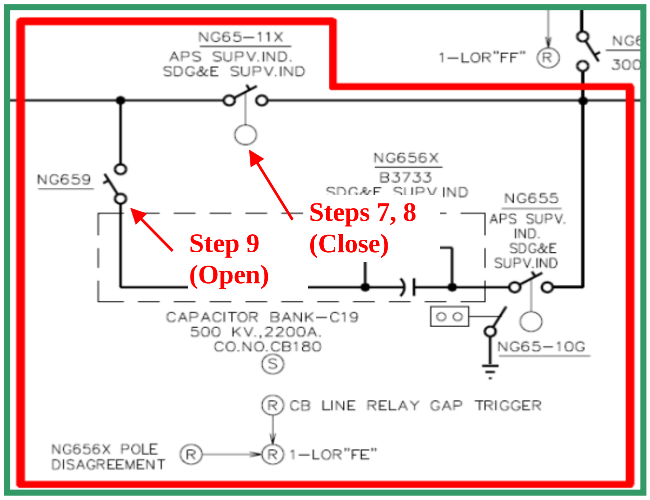
[34] Grounds are temporary protective connections that are run from conductive parts of lines, structures, and equipment, to earth or some other grounding system that substitutes for earth. If the isolated equipment is accidentally energized, grounds are intended to: (1) limit the voltage rise at the worksite to a safe value; and (2) provide a pathway for fault current to flow, thereby allowing upstream protective devices to trip.

[35] In human performance analysis, this is known as a "place keeping" error, by failing to physically mark steps as they are completed.

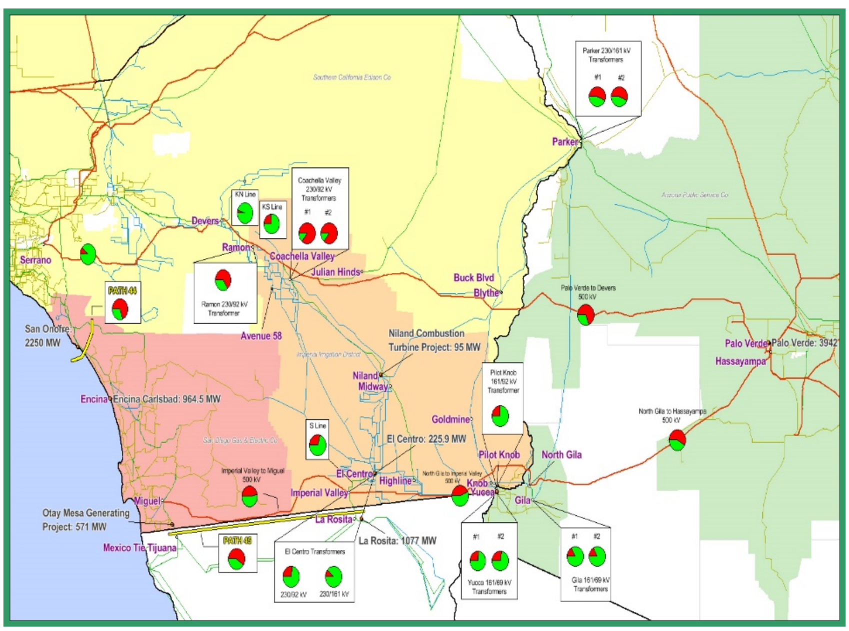
[36] An electric arc is a luminous discharge of current that is formed when a strong current jumps a gap in a circuit.

Figure 6: APS Series Capacitor Bank



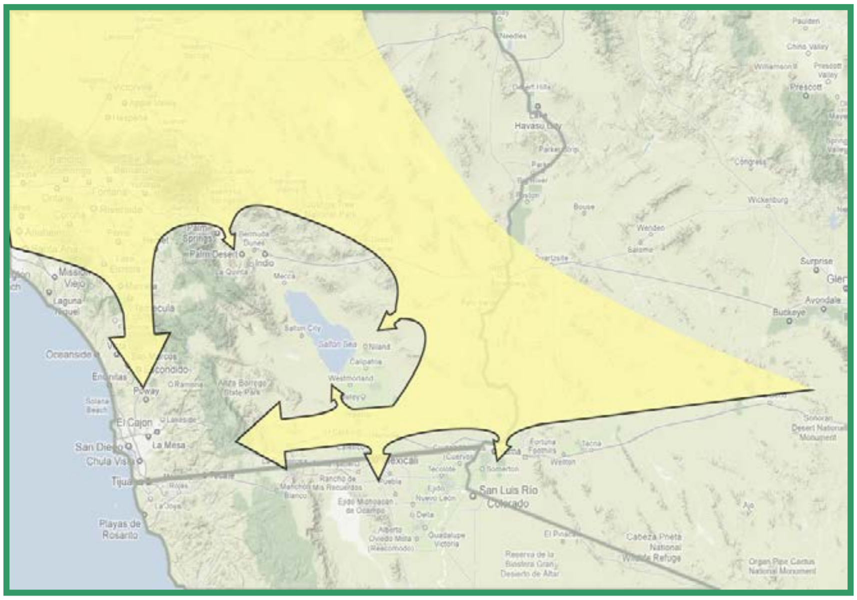
Phase 1 Graphics[37]

Pre-disturbance (000)



37 For the dial graphics shown here, green indicates available capacity on the facility, red indicates that the facility is fully loaded to its normal limit, blue indicates the amount by which the facility is overloaded, and gray indicates that the facility has tripped or load has been lost. For the power flow graphics, black borders indicate islanding, and gray areas bounded by black are those where load was lost.

15:27:00



B. Phase 2: Trip of the Hassayampa-North Gila 500 kV Line

Phase 2 Summary:

- Timing: 15:27:39 to 15:28:16, just before CV transformer No. 2 trips
- H-NG trips due to fault; APS operators believe they will restore it quickly and tell WECC RC
- H-NG flow redistributed to Path 44 (84% increase in flow), IID, and WALC systems
- CV transformers immediately overloaded above their relay setting
- At end of Phase 2, loading on Path 44 at 5,900 out of 8,000 amps needed to initiate SONGS separation scheme

At 15:27:39, the arc that had developed on each phase of the disconnect switch lengthened as the switch continued to open, to the point where two phases came into contact. This caused H-NG to trip to clear this phase-to-phase (A to C) fault. The high-speed protection system correctly detected the fault and tripped the line in 2.6 cycles (43 milliseconds). After discussion with the technician, APS operators erroneously believed that they could return the line to service in approximately 15 minutes, even though they had no situational awareness of a large phase angle difference caused by the outage. More time would have been needed to redispatch generation to reduce the phase angle difference to the allowed value. APS system operators informed CAISO, Salt River Project (SRP), and WECC RC that the line would be reclosed quickly, even though they were unaware that this was not possible because of the large phase angle difference that existed between Hassayampa and North Gila. The inquiry's simulation indicates that the post-contingency angular difference was beyond the allowed North Gila synch-check relay reclosing angle setting of 60 degrees, and there would not have been adequate generation for redispatch to reduce the phase angle difference to within the allowed value. APS operators were only able to see the angular difference on EMS displays after isolating the North Gila capacitor bank and re-energizing H-NG from the Hassayampa substation (before closing at North Gila).

H-NG, which has a flow limit of 1,800 MW[38] with a 30 minute emergency rating of 2,431 MW, was carrying 1,391 MW flowing from east to west along the SWPL at the time of the trip. As a result of the line trip, flows redistributed across the remaining lines into the San Diego, Imperial Valley, and Yuma areas. The IID and WALC systems, located between the two parallel high voltage Paths, were forced to carry approximately 23% of the flow that had initially been carried by H-NG. The majority of the flow diverted to Path 44, as discussed below.

Immediately after the loss of H-NG, the loading on both of IID's CV transformers increased to 130% of their normal rating and 118.5% of their emergency rating. The time overcurrent relays on the CV transformers picked up because the current flow was above the overcurrent relay setting, and began timing according to their very inverse[39] time delay. The CV transformers would both trip within 40 seconds of the loss of H-NG. At the same time, loading on IID's Ramon 230/92 kV transformer increased to 94% of its normal rating and 85% of its emergency rating. Three seconds after the loss of H-NG, SCADA metering for the CV transformer banks stopped recording accurate readings due to remote terminal unit (RTU) exceeding maximum scale. IID and WECC RC no longer had accurate information about or situational awareness of the loading on these important transformers.

IID also experienced increased loading on several of its 161 kV lines immediately after the loss of H-NG: Blythe-Niland and Knob-Pilot Knob loading increased by 49% and 55%, respectively. Flows on IID's S Line reversed from south to north (SDG&E to IID) to north to south (IID to SDG&E) during this phase of the event, indicating that

[38] *See* footnote 31, *supra*.

[39] "Very inverse" describes the time/current characteristic of the relays' time delay which is inversely proportional to the current magnitude sensed by the relay. That is, the greater the current, the less time before the relay will trip.

flows intended for SDG&E were being routed through IID's 161 and 92 kV systems. While IID was aware of the flow changes on the S Line, it was unable to see the loss of H-NG in real time.

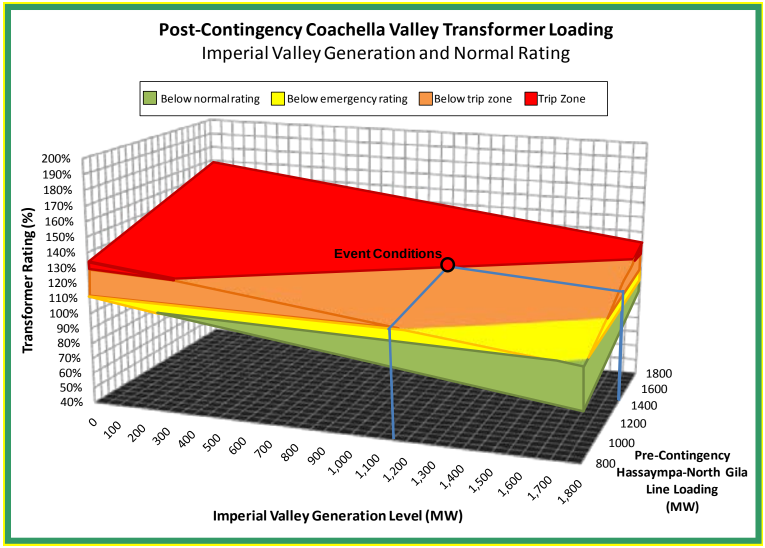
Flows on WALC's Gila 161/69 kV transformers increased from approximately 12 MVA to 60 MVA, still well below their normal limits of 75 MVA each, but indicative of the sudden increase in flows on WALC's system just after the loss of H-NG. WALC also experienced significant voltage drops on its 161 kV system, particularly at Blythe (6.9% drop) and Kofa (6.7% drop) substations, due to the increased flows on that system.

The loss of H-NG interrupted the southern 500 kV path into San Diego. The majority of the flow diverted to the northern entry to SDG&E, Path 44. Flow on Path 44 increased by approximately 84%, from 1,293 MW to 2,362 MW. This flow equates to a tie current of 5,900 amps relative to the 8,000 amps required to initiate the SONGS separation scheme.

Because so much of the flow on H-NG was intended for San Diego, the inquiry considered whether increasing internal generation in SDG&E's area would have avoided the cascading outages.[40] ***Figure 7***, on the next page, illustrates post-contingency loading on the CV transformers based on pre-contingency loading on H-NG and the generation level at IID's and SDG&E's jointly owned Imperial Valley substation. The red area on the graph indicates the large zone in which loading below H-NG's 1,800 MW SOL would load the CV transformers above their trip point. This area demonstrates the non-secure N-1 operating point of the CV transformers. It shows that the operating conditions that would reduce the loading on the transformer are: increased generation at Imperial Valley, reduced flow on H-NG before it tripped, or both. For example, the graph indicates that for the same amount of transfer on H-NG, additional generators connected at Imperial Valley would reduce the post-contingency loading on the CV transformers.

[40] The inquiry's analysis is not intended to suggest specific generation adjustments that could have been made by specific entities on September 8, 2011, but rather to show the extent to which the affected entities are interdependent.

Figure 7 : Post-Contingency CV Transformer Loading Based on Imperial Valley Generation



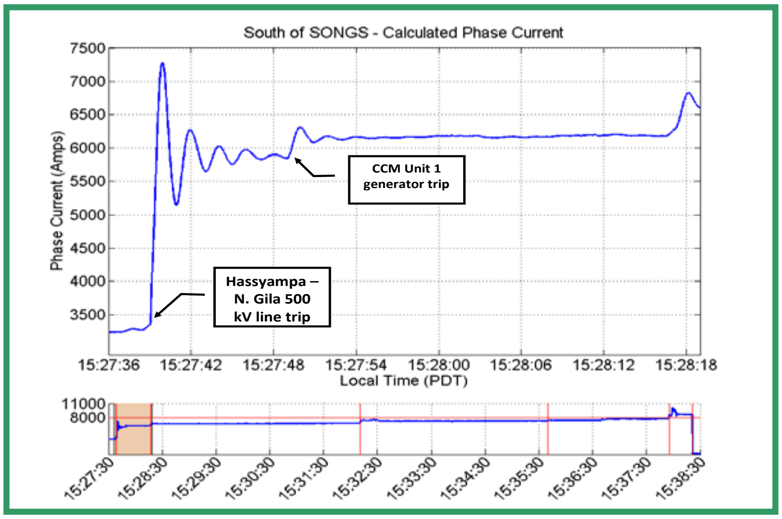
In general, adding generation in San Diego, CFE, or Imperial Valley and backing down generation in APS's system (east of Path 49) would reduce the loading on IID's 92 kV system for the loss of H-NG. For example, an additional 600 MW of generation at Imperial Valley and a reduction of generation in APS's system by the same amount would have reduced the pre-contingency loading on H-NG by 20% and improved the post-contingency voltage in WALC's Blythe area by approximately 4%. Under this condition, the loading on the CV transformers for the loss of H-NG would be approximately 111% of their normal rating (166 MVA), well below their trip setting of 127%. This is a further demonstration of the importance of including all facilities when deriving SOLs.

After seeing the alarm for the loss of H-NG, the WECC RC operator promptly called the line's operator, APS. APS told WECC RC it could get H-NG restored within minutes. While WECC RC was monitoring Rated Paths, it took no action specific to Path 44, believing it would take five or ten minutes for APS to restore H-NG. As the entire event took only 11 minutes, WECC RC did not issue any directives in connection with the loss of H-NG.

Shortly after H-NG tripped, at 15:27:49, one of the combustion turbines at CFE's Central La Rosita substation tripped while producing 156 MW. This trip may have been triggered by transients.[41] caused by the initial fault at North Gila and subsequent trip of H-NG. Loss of this unit further increased the flow on Path 44, raising the current to 6,200 amps out of the 8,000 needed to initiate the SONGS separation scheme. However, the La Rosita trip alone was not significant in causing the cascading that followed.[42] CFE was also unaware in real time that H-NG had tripped. After losing the Central La Rosita unit, CFE was unable to recover its ACE with its own resources, and at 15:30, it requested 158 MW of emergency assistance from CAISO for the remainder of the hour.

Phase 2 Graphics

South of SONGS – Calculated Phase Current



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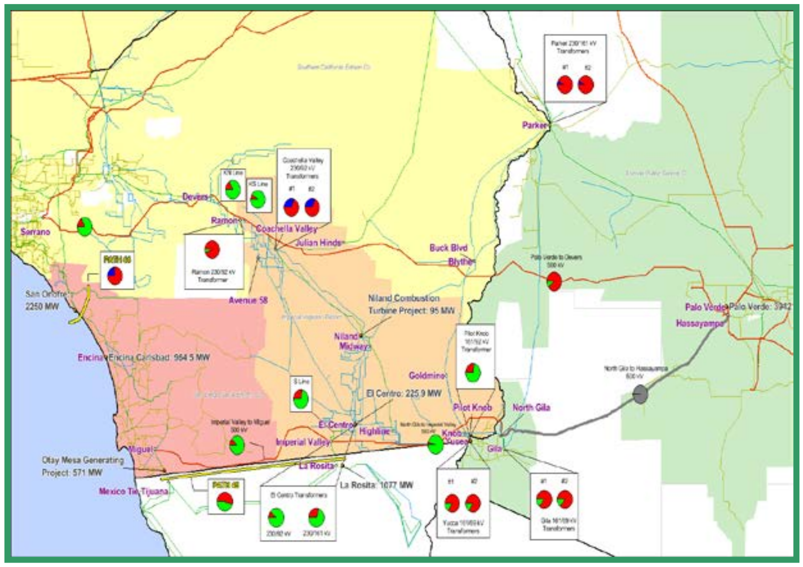
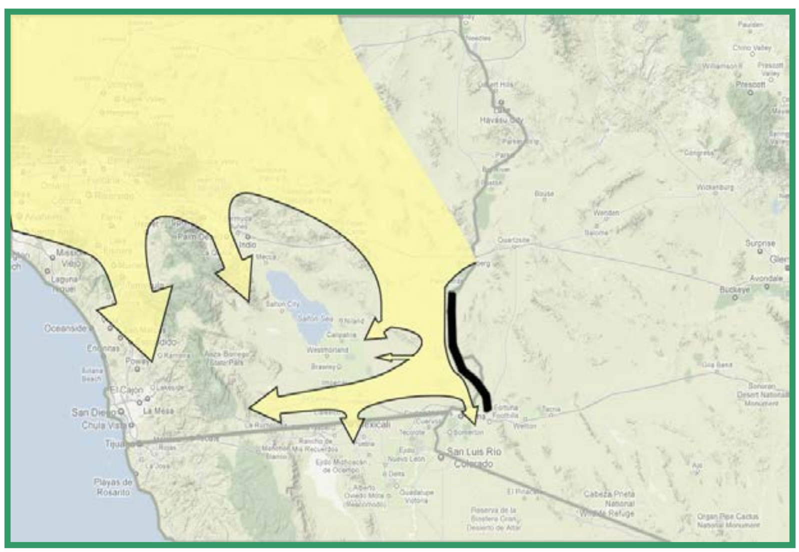
[41] *See* footnote 21. CFE stated that the trip was triggered by transients.

[42] The Modeling and Simulation team conducted a "what if" simulation and determined that, even without the inadvertent tripping of 160 MW of generation at La Rosita, the overloads and ensuing blackout would still have occurred.

15:27:39 – The Hassayampa- North Gila 500 kV line tripped.



15:27:40



C. Phase 3: Trip of the Coachella Valley 230/92 kV Transformer and Voltage Depression

Phase 3 Summary:

- Timing: 15:28:16, when CV transformer bank No. 2 tripped, to just before 15:32:10, when Ramon transformer tripped
- Both CV transformers tripped within 40 seconds of H-NG tripping
- IID knew losing both CV transformers would overload Ramon transformer and S Line connecting it with SDG&E
- Severe low voltage in WALC's 161 kV system
- At end of Phase 3, loading on Path 44 at 6,700 amps out of 8,000 needed to initiate SONGS separation scheme

At 15:28:16, less than a minute after H-NG tripped, IID's CV transformer bank No. 2 tripped on the 230 kV side. The CV overload protection relays detected an overload immediately after H-NG was lost. The overloads were caused by through-flows on IID's 92 and 161 kV systems which parallel APS's 500 kV system. The normal ratings for these transformers are 150 MVA, but immediately after H-NG tripped, each CV transformer was carrying more than 191 MVA. The relays were set to trip at approximately 127%[43] of the transformers' normal ratings, or 191.2 MVA at nominal voltage. The inverse time relays took 37.5 seconds to trip bank No. 2 and 38.2 seconds to trip bank No. 1. Thus, CV bank No. 1 tripped only 677 milliseconds after bank No. 2, again on the 230 kV side. Although the primary winding or high side voltages of the CV transformers are 230 kV, the banks were not considered as elements of the BES because their secondary winding or low side voltages are below 100 kV. As discussed in detail in Section IV, because these transformers and the underlying 92 kV system were not classified as elements of the BES, IID, neighboring TOPs, and WECC RC did not assess the impact of critical external contingencies on overloading the CV banks, the effect of losing the CV banks and the subsequent impact on the Ramon bank, and, finally their overall adverse effect on BPS reliability.

IID was aware of the potential for local cascading if the CV transformers tripped. IID's next-day plan for September 8, 2011, which was not based on updated studies, indicated that if both CV transformers tripped,[44] the Ramon 230/92 kV transformer would trip and the S Line tie with SDG&E would overload to 109% of its normal rating. The next-day plan also indicated that this overloading, in turn, would result in tripping generation because the S Line RAS trips generation supplied to Imperial Valley when the S Line loads to 108% of its normal rating. IID's next-day mitigation plan for loss of the CV transformers required starting turbines at Coachella and Niland and asking CAISO to

[43] IID's transformer protection philosophy specifies trip settings at 120% of normal ratings. IID chose the closest available relay tap, which was approximately 127% of the normal rating.

[44] This contingency scenario had nothing to do with H-NG tripping. IID's studies did not show any effect on the CV banks resulting from the loss of H-NG.

redispatch generation to relieve the S Line. This was a post-contingency mitigation plan. But after the event, IID's operator admitted that if the CV transformers tripped on overload, he would have "very little time to mitigate the Ramon [transformer], if at all." Even the quickest-starting turbines take about 10 minutes to start and ramp to full load, but IID effectively had only four minutes before the Ramon transformer would trip, after the loss of the CV transformers.

The loss of the CV banks caused flows on the S Line between SDG&E and IID to again reverse direction. Because its load exceeded internal generation, IID began pulling power from SCE through SDG&E due to the loss of key facilities in IID's northern system. The tripping of the second CV bank also open-ended the Coachella Valley-Ramon 230 kV "KS" Line (at CV), which was carrying about 41 MVA. This further increased loading on the Mirage-Ramon 230 kV line and through-flow from IID's 230 kV collector system through Devers, but had little effect on the overall disturbance. By 15:31:35, IID's operators switched in 92 kV capacitor banks at Avenue 42, Avenue 58, and Highline due to low voltage.

The loss of IID's two CV transformers caused the aggregate current on Path 44 to increase from 6,200 amps to 6,600 of the 8,000 amps necessary to trigger the SONGS separation scheme. However, by the end of this Phase aggregate Path 44 current reached 6,700 amps.

The loss of the CV banks caused a severe voltage depression on the WALC 161 kV system south of Blythe. During this period, loads in that area (largely irrigation pumps) were highly susceptible to motor stalling, which can create additional reactive demand and exacerbate transmission loading, both of which contribute to additional voltage decline. See ***Figure* 8**, on the next page. At 15:28:18, the Blythe 161 kV bus alarmed at 142 kV (0.882 per unit).[45] WALC continued to experience severe low voltage on its 161 kV system until the S Line tripped at 15:38:02.4.

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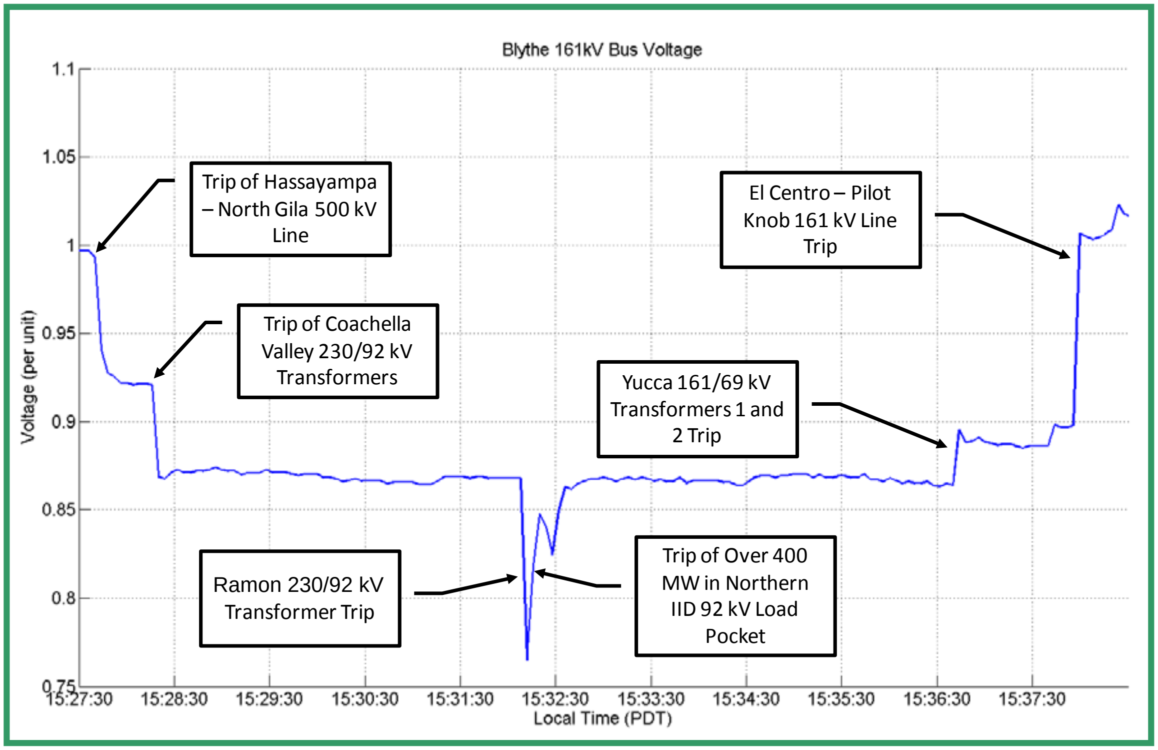
[45] Other alarms and low voltage readings followed throughout WALC's system one to nine seconds later, including the Parker-Kofa 161 kV line, which alarmed for overload at 169 MVA (167 MVA rating); Kofa 161 kV bus voltage recorded at 143 kV (0.888 per unit); Knob 161 kV bus voltage recorded at 142 kV (0.882 per unit); Parker 161 kV bus voltage recorded at 149 kV (0.925 per unit); Gila and Goldmine 161 kV bus voltages recorded at 144 kV (0.894 per unit); and Parker 230 kV bus voltage recorded at 222 (0.965 per unit).

Figure 8: Blythe 161kV Voltage

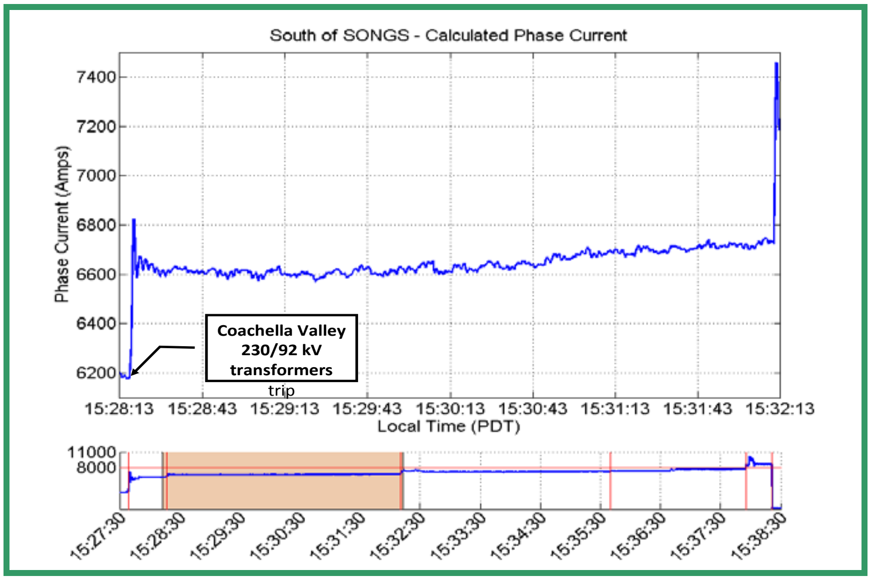


On September 8, 2011, CAISO had partial visibility of IID's system, but could not see that the CV banks had tripped. Prior to the event CAISO and IID had been working together to increase their mutual visibility and those efforts are continuing. Currently, CAISO receives loading data from the 230 kV side of the CV transformers.

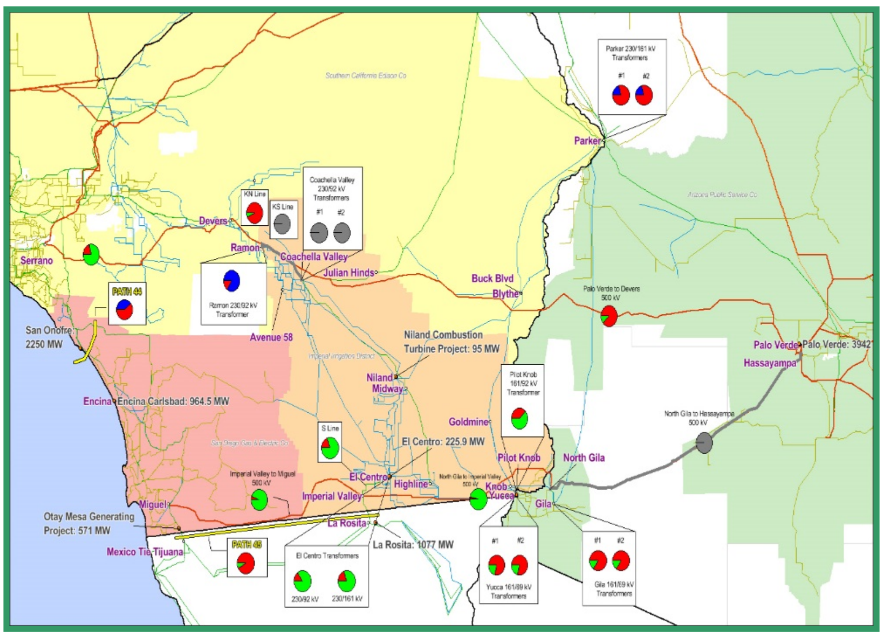
Despite the fact that it did not consider the CV banks to be part of the BES, WECC RC does observe much of IID's 92 kV system in real time, including the CV banks. The WECC RC operator did notice the CV transformers trip, but he was focused on when APS would return H-NG to service.

Phase 3 Graphics

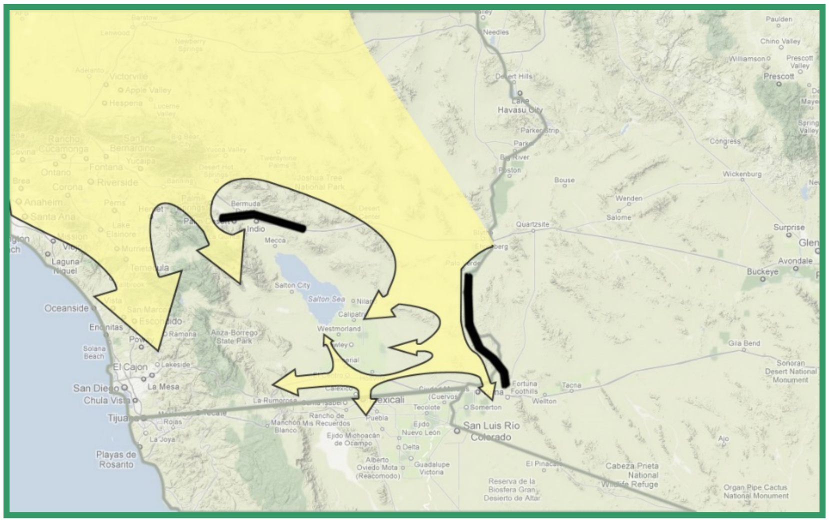
South of SONGS – Calculated Phase Current



15:28:17 – Two Coachella Valley 230/92 kV transformers and the Coachella Valley Ramon 230 kV "KS" line tripped. (030)



15:28:18



D. Phase 4: Trip of Ramon 230/92 kV Transformer and Collapse of IID's Northern 92 kV System

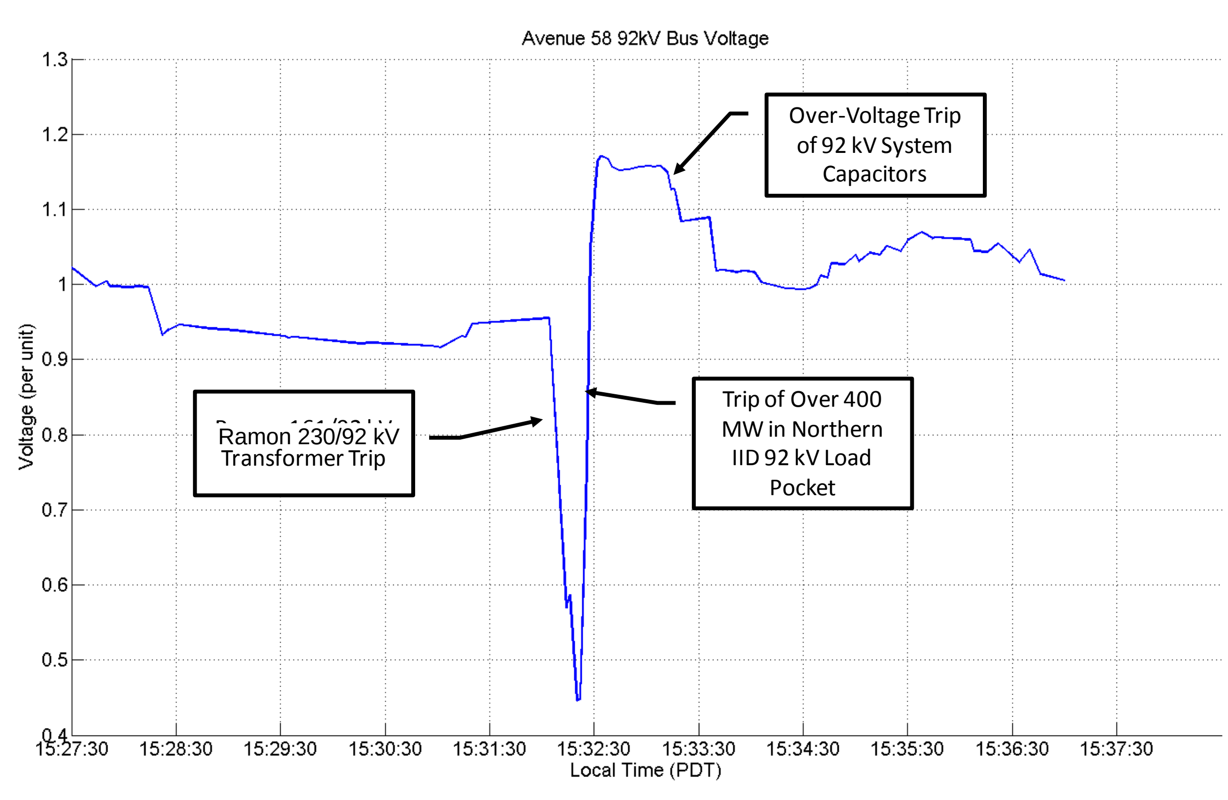
Phase 4 Summary:

- Timing: 15:32:10 to just before 15:35:40
- IID's Ramon 230/92 transformer tripped at 15:32:10, was set for 207% of its normal rating instead of its design setting of 120%, which allowed it to last approximately four minutes longer than CV transformers
- IID experienced undervoltage load shedding, generation and transmission line loss in its 92 kV system
- Path 44 loading increased from approximately 6,700 amps, to as high as 7,800 amps, and ended at around 7,200 amps (out of 8,000 needed to initiate the SONGS separation scheme)

At 15:32:10.621, less than five minutes after the trip of H-NG, IID's Ramon 230/92 kV transformer tripped on the 92 kV side. The normal rating for this transformer was 225 MVA, and its relays were set to trip above 207% of its normal rating, or 466 MVA. Before it tripped, the SCADA metering for the Ramon bank had stopped recording accurate readings due to RTUs exceeding maximum scale, just as for the CV banks. Following the loss of the CV transformers, the inverse time relays took less than four minutes to trip the Ramon transformer. IID had intended to set the Ramon transformer to trip at 120% of its normal rating. Had it been set at this level, the Ramon transformer would have tripped almost immediately after the loss of the CV transformers, approximately four minutes earlier than the time of its actual trip. IID believed that the Ramon transformer would overload beyond the trip point upon the loss of both CV transformers. Its next-day plan noted, "the Ramon Bank #1 transformer will overload and relay out of service because the overcurrent settings are set to trip at 120%." IID's next-day plan relied on a post-contingency operating philosophy of starting the Coachella Gas Turbines to mitigate overloads following the loss of the CV transformers, but the plan was unrealistic as IID would not have had time to start any additional generation between the loss of the CV transformer banks and the loss of the Ramon transformer.

Within less than one second after the loss of the Ramon transformer, automatic distribution undervoltage protection in IID's northern 92 kV system began tripping distribution feeders and shedding load. From 15:32:11 to 15:33:46, 444 MW of IID's load tripped, with nearly half of the load being shed within 10 seconds of the Ramon transformer tripping. As illustrated in ***Figure* 9**, below, the severe voltage depression following the loss of the Ramon transformer appears to have prompted a local voltage collapse within IID's northern 92 kV system, evidenced by both the steep drop-off in voltage as well as a sharp rise in reactive power flow due to motor stalling.

Figure 9: 92kV Voltage (per unit) at Avenue 58



The loss of IID's northern resources and subsequent system response caused IID to lose multiple generators connected to its 92 kV system, including IID's Niland Gas Turbine 2 (generating 45 MW), IID's CV Gas Turbine 4 (generating 20 MW), independent power producer Colmac's unit (generating 46 MW), and IID's Drop 4 Unit 2 Hydro Generator (generating 10.3 MW).

IID also began losing transmission lines. The Blythe-Niland 161 kV "F" Line, which saw increased loading during Phase 2, tripped at 15:32:13 (approximately 3 seconds after loss of the Ramon banks). Its normal rating was 165 MVA, and it was set to trip at 129% of the normal rating (212 MVA at nominal voltage) with a 3-second time delay.[46] The Niland-CV 161 kV "N" Line, carrying 83 MVA, tripped approximately 2 seconds later at 15:32:15.29 due to Zone 3 distance protection.[47]

In WALC's territory, the Blythe-Goldmine-Knob and Parker-Kofa 161 kV lines overloaded approximately four seconds after the Ramon transformer tripped, at 15:32:14, but did not trip. These lines each had a normal rating of 167 MVA, but were loaded to 177 MVA. Power flows redistributed through the Parker and Blythe areas after IID lost the Blythe-Niland line. WALC took some actions in an attempt to arrest the voltage depression it was experiencing, including a directive to start hydropower generation units Parker 3 and 4 for voltage support at 15:34:07. At the time, Parker area voltage was at 150 kV (0.932 per unit). WALC also switched in shunt capacitors on the 69 kV system at Gila and Kofa. At the time, voltage at Gila was at 65.5 kV (0.906 per unit) while Kofa was at 59 kV (0.86 per unit).

CAISO attempted to bring on generation through its exceptional dispatch[48] process to bring Path 44 back within its limit of 2,500 MW, anticipating that it had 30 minutes to do so. At 15:35, it dispatched the Larkspur No. 2 peaking unit (rated 50 MW)

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[46] Based on the last available SCADA scan before the line tripped, the voltage at Blythe was at 123.1 kV (0.765 per unit) and the line was loaded to 172 MVA. Based on these measurements, the line was carrying 807 amps at the last time recorded; the relay was set to trip with a 3-second time delay at 762 amps.

[47] A distance relay is a relay that compares observed voltage and current on a line and operates when that ratio is below its preset value. Zone 3 relays are typically set to protect against faults that are more than one substation away from the observed line as backup protection. An appropriate time delay should be set in the relay to give the remote station relays the opportunity to operate and isolate the minimum amount of equipment necessary to clear the fault. A common issue with the application of Zone 3 relays is that they can restrict the loading on transmission lines (e.g. the N Line) during abnormal system conditions like those present on September 8th.

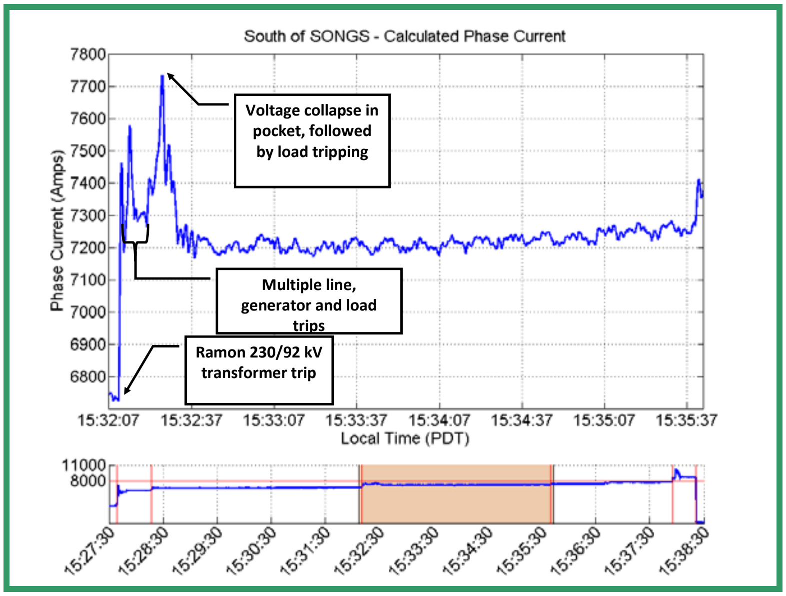
[48] CAISO's exceptional dispatch process involves calling on generators outside of the market automated dispatch process.

within San Diego, which has a 20-minute start-up time. Also at this time, APS began taking steps to restore H-NG by completing the bypass of the series capacitor bank.

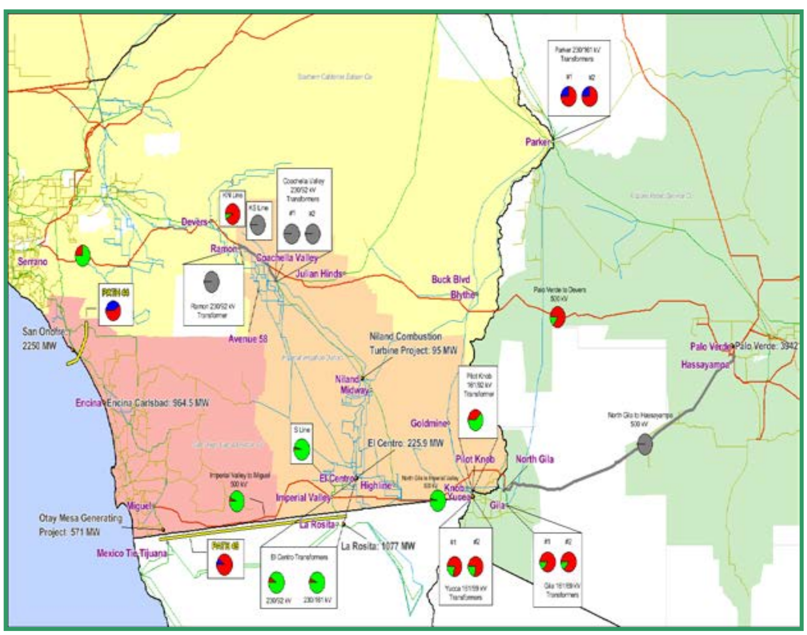
During Phase 4, aggregate loading on the South of SONGS 230 kV transmission lines increased from approximately 6,700 amps to as high as 7,800 amps. The loading settled around 7,200 amps and remained there for the rest of Phase 4.

Phase 4 Graphics

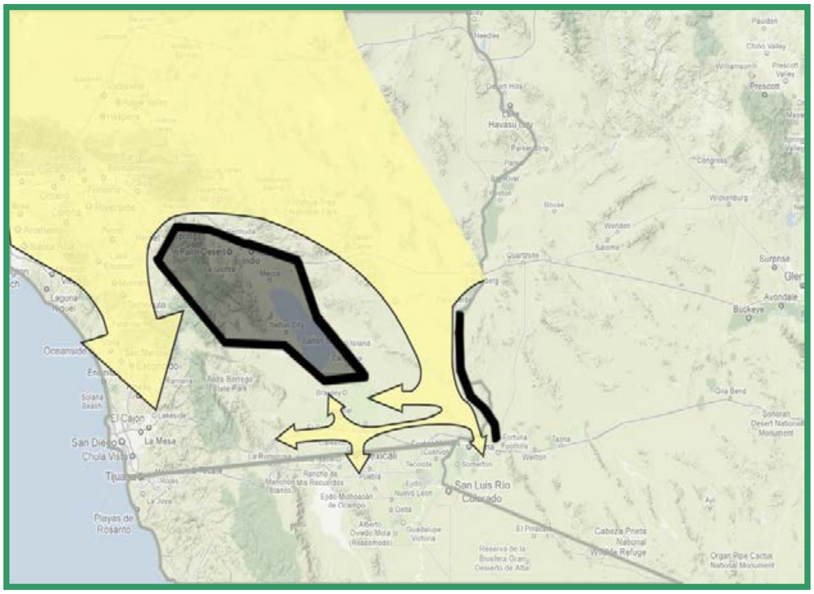
South of SONGS – Calculated Phase Current



Time: 15:32:10 – The Ramon 230/92 kV transformer tripped and IID shed 444 MW of load. (110)



Time: 15:32:35



E. Phase 5: Yuma Load Pocket Separates from IID and WALC

Phase 5 Summary:

- Timing: 15:35:40 to just before 15:37:55
- The Gila and Yucca transformers tripped, isolating the Yuma load pocket to a single tie with SDG&E
- Path 44 loading increased from 7,200 to 7,400 amps after Gila transformer tripped, and ended at 7,800 amps after loss of the Yucca transformers and YCA generator (very close to the 8,000 amps needed to initiate the SONGS separation scheme)

At 15:35:40, approximately eight minutes after H-NG tripped, WALC's Gila 161/69 kV transformers tripped due to time-overcurrent protection. The two transformers are each rated 75 MVA, but the 69 kV bus section that connects the transformers to the rest of the 69 kV substation is rated 1,200 amps (143 MVA at nominal voltage), and the overcurrent protection is set accordingly at 1,200 amps. The bus was carrying 1,312 amps at the time of the trip.

One minute later, at 15:36:40, the Yucca 161/69 kV transformers 1 and 2 tripped when their common 69 kV breaker tripped due to overload protection. Bank No. 1 is owned by IID and is rated 73 MVA, and bank No. 2 is owned by APS and is rated 75 MVA. The IID Yucca generator and four out of the six APS combustion turbines connected to APS's 69 kV system were offline at the time of the event, as was the IID GT21 combustion turbine on the 161 KV side. These generators may have supported load in the area had they been in service. Almost immediately, the Pilot Knob breaker on the Pilot Knob-Yucca 161 kV "AX" transmission line, which is effectively the 161 kV breaker for the Yucca 161/69 kV transformers, received a direct transfer trip from the Yucca transformer overload protection, thereby tripping the AX Line. As a result of the loss of the Yucca and Gila transformers, the Yuma load pocket was isolated to only one tie to the SDG&E system, causing loading on each N. Gila 500/69 kV transformer bank to increase from 57 MVA to 164 MVA.

Less than one second after the Yucca transformers and AX Line tripped, at 15:35:40, the Yuma Cogeneration Associates (YCA) combined cycle plant on the Yuma 69 kV system tripped. The combustion turbine is rated at 35 MW and the heat recovery unit is rated at 17 MW, totaling 52 MW. It appears that both units were fully loaded at the time of the trip. The cause of the trip is unknown, but the loss of the YCA unit hastened the collapse of the Yuma load pocket.

Approximately one minute later, at 15:37:41, a common 161 kV breaker tripped IID's Pilot Knob 161/92 kV transformers Nos. 2 and 5 for No. 2 overload protection. The overload protection was set to trip the banks at 121% of the normal rating (37.5 MVA at nominal voltage).

At WALC's request, between 15:36:48 and 15:36:52, SCE directed Metropolitan Water District operators to drop 80 MW of pumping load attached to the Gene substation (near Parker) to improve 230 kV voltage support at Parker in an attempt to arrest declining voltages.

As it had done during Phase 4, CAISO ordered exceptional dispatch to bring Path 44 below its 2,500 MW limit. At 15:36:00, CAISO called SCE and ordered an exceptional dispatch of Larkspur Peaking Unit No. 1 (rated 50 MW), and Kearny GT2 and GT3 (each rated 59 MW) to go to full load. The Larkspur unit takes 20 minutes to start, and the Kearny units are 10-minute "quick start" peaking generators. All of these units were offline at the time, and they were unable to come online before the system collapsed.[49]

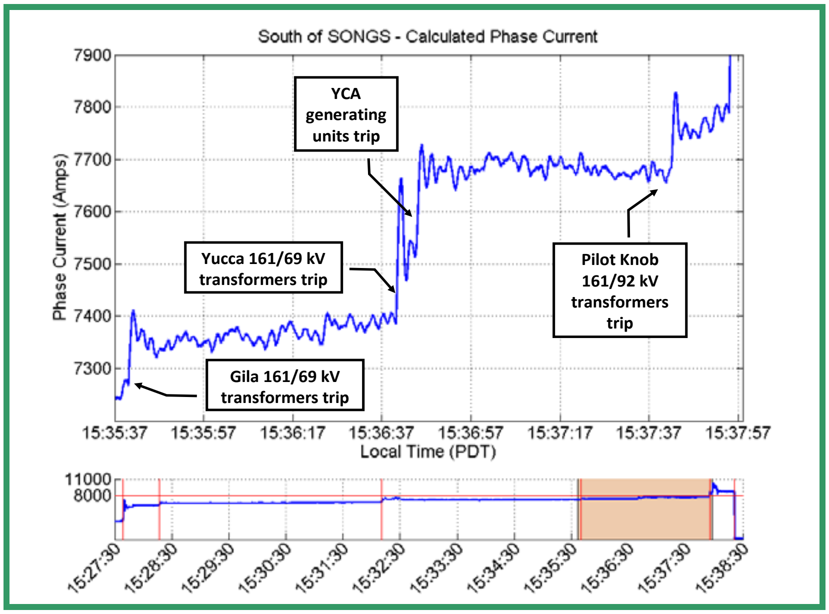
The tripping of the Gila 161/69 kV transformers caused the aggregate loading on Path 44 to increase from approximately 7,200 amps to approximately 7,400 amps, out of the 8,000 amps necessary to initiate the SONGS separation scheme. After the loss of the

[49] Larkspur generation is connected to the SDG&E 69 kV system south of Otay Mesa, and Kearny generation is connected to the SDG&E 69 kV system in northern San Diego.

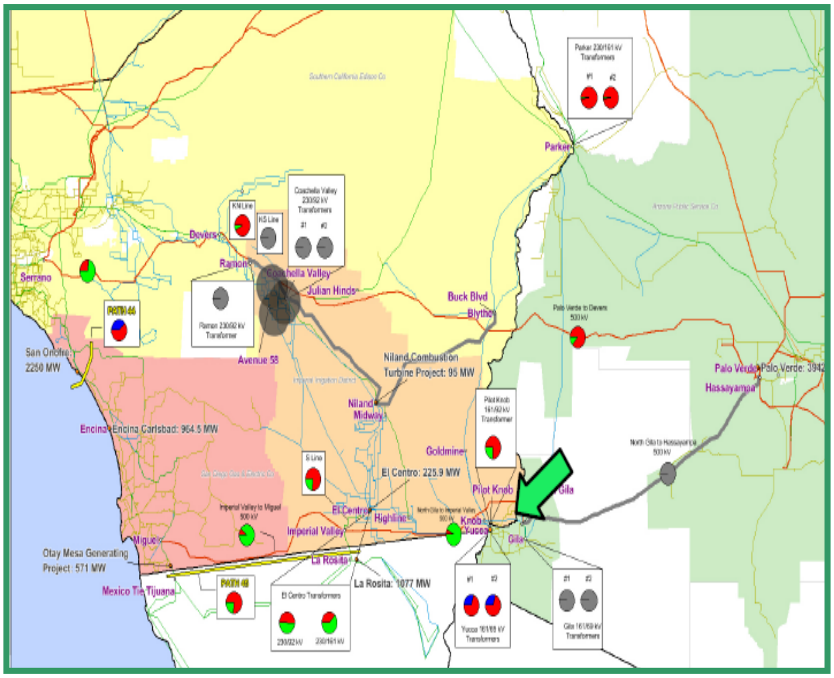
Yucca 161/69 kV transformers, the YCA plant, and the Pilot Knob 161/92 kV transformers, the loading further increased to approximately 7,800 amps.

Phase 5 Graphics

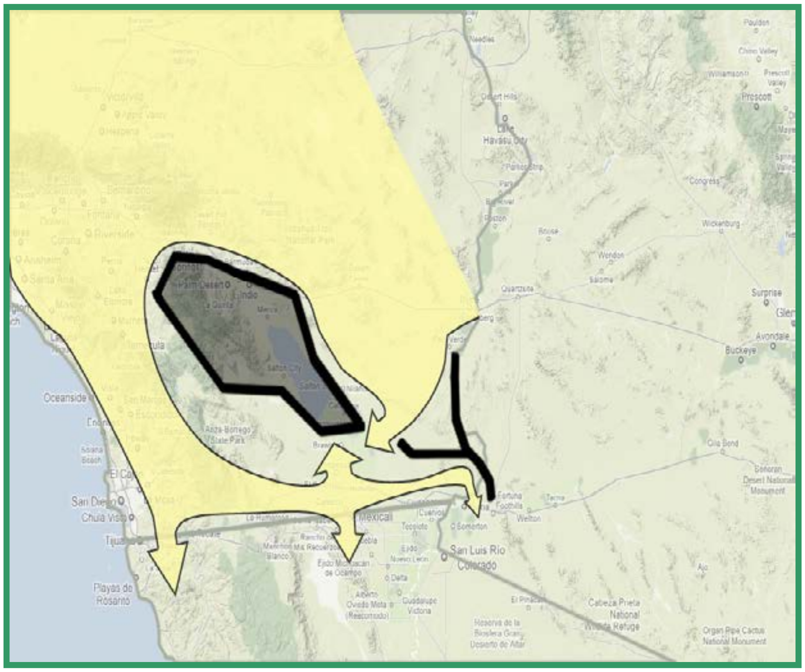
South of SONGS – Calculated Phase Current



Time: 15:35:31 – Yuma Cogen (YCA) tripped. (180)



Time: 15:37:42



F. Phase 6: High-Speed Cascade, Operation of the SONGS Separation Scheme and Islanding of San Diego, IID, CFE, and Yuma

Phase 6 summary:

- Timing: 15:37:55 to 15:38:21.2
- IID's El Centro-Pilot Knob line tripped, forcing all of IID's southern 92 kV system to draw from SDG&E via the S Line
- S Line RAS operates, tripping generation at Imperial Valley and worsening the loading on Path 44
- S Line RAS trips S Line, isolating IID from SDG&E
- Path 44 exceeds trip point of 8,000 amps, to as high as 9,500 amps
- SONGS separation scheme operates and creates SDG&E/CFE/Yuma island

When the El Centro-Pilot Knob 161 kV line tripped at 15:37:55 (10 minutes after loss of H-NG), it isolated the southern IID 92 kV system onto a single transmission line from SDG&E: the S Line. Forcing all of the remaining load in IID to draw through the SDG&E system pushed the aggregate current on Path 44 to 8,400 amps, well above the trip point of 8,000 amps. If the aggregate current on Path 44 remained above 8,000 amps, the definite minimum time relay[50] would initiate the SONGS separation scheme to separate SDG&E from SCE at SONGS.

IID's El Centro-Pilot Knob 161 kV line open-ended at El Centro when a 161 kV breaker at El Centro tripped on Zone 3 relay protection[51] with a one second delay. The apparent impedance detected on the Zone 3 relay at El Centro was hovering near its trip zone immediately following the Pilot Knob 161/92 kV transformer trips (12 seconds earlier), but did not cross into the Zone 3 tripping region until this time.

By this time in the event, the South of SONGS lines were San Diego's only source of critical imported generation, and were also keeping IID and CFE's Baja California Control Area from going dark. If the aggregate current was brought below 8,000 amps, the blackout could have been avoided, but at this point no operator action could have occurred quickly enough to save the South of SONGS Path. Had there been formal operating procedures that recognized the need to promptly shed load as the aggregate current approached 8,000, and had operators been trained on the 8,000 amp set point, it is possible that operation of the SONGS separation scheme could have been averted by earlier control actions.

Milliseconds after the loss of IID's El Centro-Pilot Knob 161 kV line, at 15:37:55.890, NextEra's Buck Boulevard combustion turbine generator tripped due to operation of SCE's Blythe Energy RAS, dropping 128 MW of generation.[52] This was caused by a reduction of counter-flows on the Julian Hinds-Mirage 230 kV line that had been created by heavy flows from the Julian Hinds-Eagle Mountain 230 kV line feeding toward the WALC 161 kV system to support the heavy north to south 161 kV flows toward Pilot Knob. When the El Centro-Pilot Knob 161 kV line tripped, those counter-flows disappeared, initiating the RAS operation. The Buck Boulevard heat recovery unit ramped down by 82 MW over the next few minutes. The Buck Boulevard combined cycle plant was generating 409 MW (535 MW rating) at the time the combustion turbine tripped. Tripping the Buck Boulevard generator did not increase loading on Path 44, because it is not located south of Path 44.

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[50] A definite minimum time relay can operate in one of two ways. When current reaches a certain value, the relay will operate with a *definite* time delay that reflects the relay's fastest operating time. Before the relay reaches that value, the time for the relay to operate is *inversely proportional to its observed current magnitude*. During the event, the relay operated while following the latter characteristic.

[51] *See* footnote 47, *supra*.

[52] The Blythe Energy RAS, among other functions, trips generation owned by NextEra to protect the Julian Hinds-Mirage 230 kV line from overloading with east to west flows for a potential loss of the Julian Hinds-Eagle Mountain 230 kV line. Buck Boulevard is connected to SCE's 230 kV system in the Blythe area.

Just three seconds after the loss of IID's El Centro-Pilot Knob 161 kV line, at 15:37.58.2, the S Line RAS at Imperial Valley Substation initiated the tripping of two combined cycle generators at Central La Rosita in Mexico. The S Line RAS currently protects El Centro's 161/92 kV transformer No. 2 by initially tripping a combination of CLR II generators when the flow on the S Line exceeds 269 MW flowing northward from SDG&E into IID. Two combustion turbines were loaded to 152 MW (193.5 MW rating), and 153 MW (193.5 MW rating), respectively, and the associated steam heat recovery unit (which also tripped following loss of the turbines) was loaded to 127 MW (159.3 rating), totaling 432 MW of generation.

Loss of the CLR II generation drove the South of SONGS flows from about 8,400 amps to about 9,500 amps, which remained above the 8,000 amp setting of the SONGS separation scheme. The inquiry's simulation showed that had the S Line tripped without the S Line RAS tripping the CLR II generation, the flow on Path 44 would have fallen below 8,000 amps to settle at an estimated 7,730 amps, and the SONGS separation scheme might not have operated.[53]

Approximately four seconds after the S Line RAS tripped the CLR II generators, at 15:38:02.4 the S Line RAS tripped the S Line itself due to flow above 289 MW toward IID from SDG&E. Tripping of this line created an IID island. IID reported that from 15:37:59 to 15:40:24, 507.85 MW of load tripped on its system, mostly in the southern 92 kV system.

The tripping of the S Line meant that IID was no longer pulling power from SDG&E and CFE through Path 44, so the aggregate Path 44 flows decreased from approximately 9,500 amps to approximately 8,700 amps, but were still above the 8,000 amps required to trigger the SONGS separation scheme.

At 15:38:21.2, not quite 11 minutes after H-NG tripped, the SONGS separation scheme operated, reconfiguring the SONGS 230 kV switchyard and isolating the SONGS generators onto the SCE system to the north. This reconfiguration effectively separated

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[53] The inquiry's simulation showed that if the S Line RAS tripped only the S Line, IID's system would still have collapsed, but San Diego and the Yuma load pocket would likely have survived. Voltages would have remained acceptable, and the 230 kV system around SONGS may have experienced minor overloads. While this would have resulted in a large phase angle difference on H-NG, the fact that the SONGS separation scheme would not have operated would have allowed time for system operators to make the load and generation changes necessary to reduce the phase angle difference.

Had the S Line RAS not operated at all, or only operated to trip the CLR II generators, Path 44 flows would have settled above the 8,000 amp threshold and thus the SONGS separation scheme would still have operated.

all five South of SONGS 230 kV transmission lines from the SONGS units and the SCE system, and separated SDG&E from the rest of the Western Interconnection. Operation of the SONGS separation scheme created an island consisting of the SDG&E system, the remaining Yuma-area load connected through the 500 kV system from Miguel to North Gila, and CFE's Baja California Control Area.

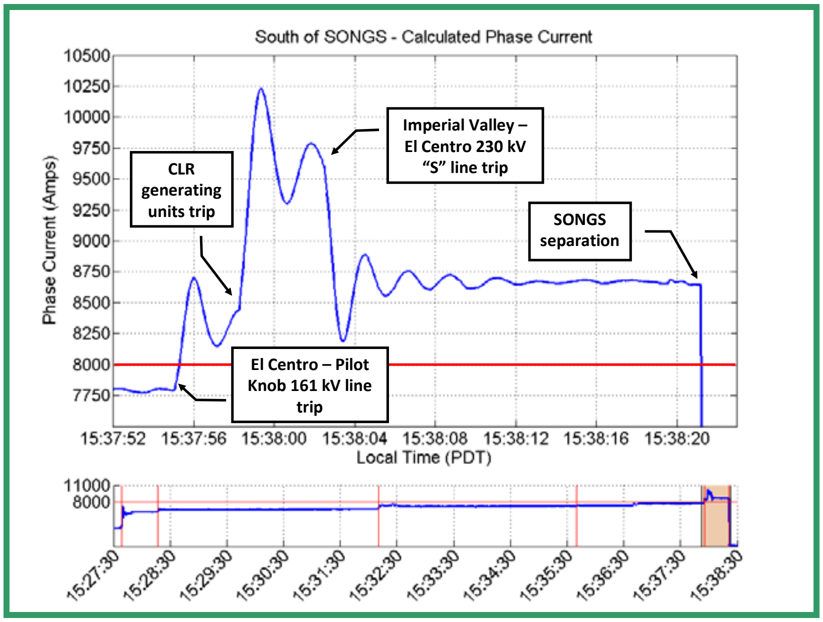
September 8, 2011, was the first time that the SONGS separation scheme had ever activated, and its effects on neighboring systems had not been studied. Although this sequence of events has focused on how the loss of elements combined over the 11 minutes to exceed the 8,000 amp SONGS separation scheme trigger, in real time, no entity was monitoring that limit or recognized the potential consequences of its operation.

WECC RC, responsible for the reliable operation of the BPS, and with having a wide area view of the BPS, did not have any alarm that would alert operators before operation of the separation scheme. Although WECC RC operators were monitoring the Path limit on Path 44, they were not watching the aggregate flows with respect to the SONGS separation scheme trigger. WECC RC operators noticed the five South of SONGS breakers open after the scheme had already operated.

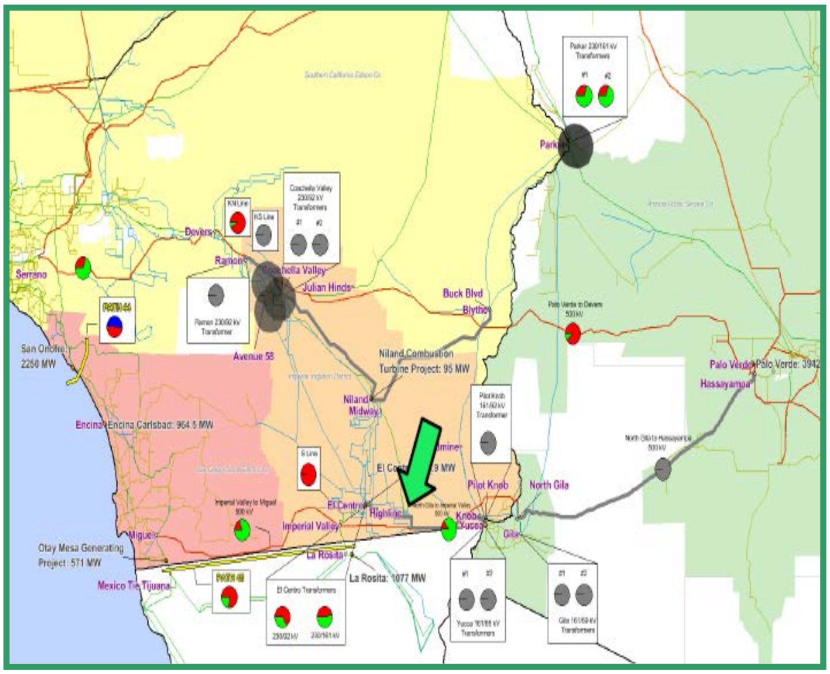
CAISO, the TOP for SDG&E and SCE, did not have any alarms specifically tied to the operation of the SONGS separation scheme either. CAISO only has alarms for when Path 44 exceeds its Path rating, but had no ability to monitor the SONGS separation scheme, set at 3,100 MW (8,000 amps). After the loss of H-NG, which caused Path 44 to exceed its Path rating, CAISO operators were primarily concerned with returning flows on Path 44 to below the Path rating of 2,500 MW, but believed they had 30 minutes to do so. Unlike Path ratings, the separation scheme would not allow CAISO operators 30 minutes to reduce flows on Path 44. CAISO did attempt to dispatch additional generation within SDG&E to reduce flows on Path 44. The other method to reduce flows would have been to manually shed load in SDG&E in time to prevent operation of the SONGS separation scheme. SDG&E estimates that it could have shed approximately 240 MW in between two and two-and-a-half minutes. However, SDG&E was never instructed to shed load and was unaware of the need to shed load.

Phase 6 Graphics

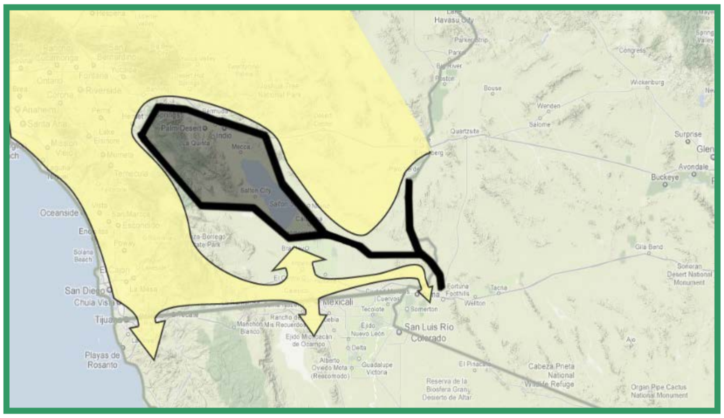
South of SONGS – Calculated Phase Current



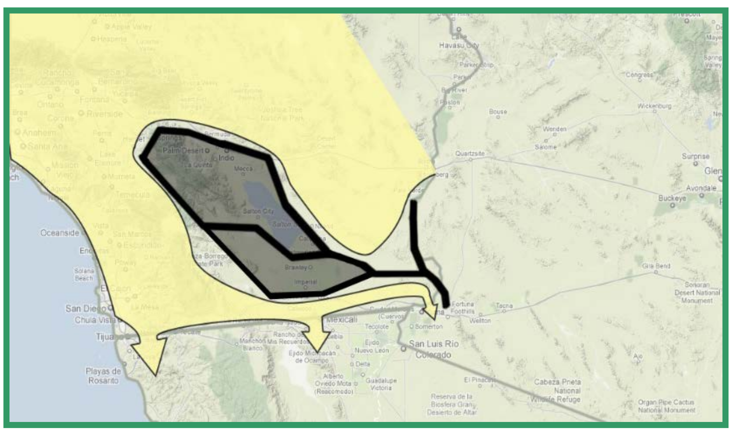
Time: 15:37:55 – The El Centro-Pilot Knob 161 kV line tripped. (230)



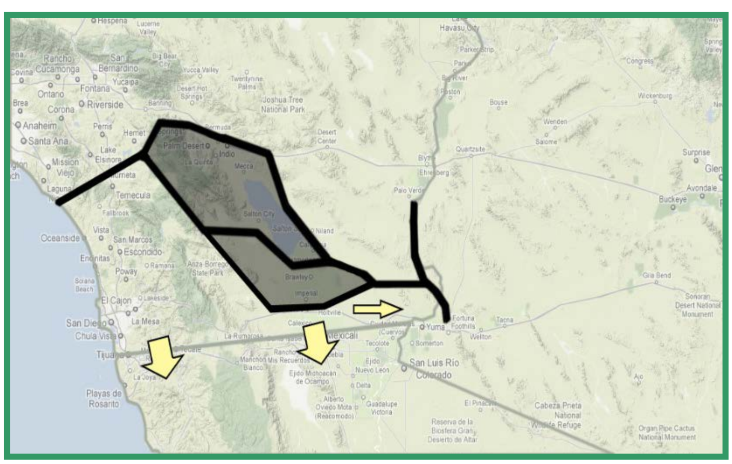
Time: 15:37:55.110



Time: 15:38:02.4



Time: 15:38:21.2



G. Phase 7: Collapse of the San Diego/CFE/Yuma Island

Phase 7 Summary:

- Timing: Just after 15:38:21.2 to 15:38:38
- Underfrequency Load Shedding (UFLS) was not able to prevent the SDG&E/CFE/Yuma island from collapsing
- SONGS nuclear units shut down even though they remained connected to the SCE side of the SONGS separation scheme

During phase 7 of the event the SDG&E/CFE/Yuma island broke into three separate islands, all of which collapsed due to an imbalance between generation and demand, resulting in severe underfrequency which tripped both loads and generation.

The SDG&E/CFE/Yuma island created by operation of the SONGS separation scheme had a significant imbalance between generation and load from the beginning. As a result, the frequency in the island rapidly declined. By less than a second after the SONGS separation scheme activated (15:38:22), the UFLS programs of SDG&E, APS, and CFE had all began activating within the island. *Figures* 10 and 11, below show the frequency within the island as it collapses. All steps of the UFLS systems activated and system frequency in the island briefly stalled at approximately 57.2 hertz (Hz). CFE's UFLS analysis showed 512 MW of load shed by 15:38:21.901.

However, the same analysis showed that three CFE generators, totaling 459 MW, tripped offline beginning at 15:38:21.905, partially negating CFE's UFLS actions. In addition, a number of smaller generators, totaling about 130 MW, tripped only 0.5 seconds later while CFE was still connected to SDG&E and while SDG&E's UFLS program was still working to shed load.[54] See *Figure* 11, below. The net effect of CFE's UFLS actions and generator trips—512 MW shed by UFLS and 590 MW of tripped generation—was that CFE's imports from SDG&E increased from approximately 440 MW to approximately 520 MW. This worsened CFE's system conditions and increased the stress on SDG&E before SDG&E's underfrequency separation protection systems opened the ties between CFE and SDG&E. SDG&E also had three generators with underfrequency protection that operated at 57.3 Hz, above the frequency at which the system leveled out. Due to these early generation losses, the frequency continued to decline below 57 Hz, which was the underfrequency setting for the majority of generators in the island. Thus, the island blacked out, shortly after separating into three sub-islands.

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[54] The fact that several generators tripped during load shedding suggests that CFE may benefit from analyzing whether its UFLS program and generator underfrequency protection systems are coordinated.

Figure 10: Frequency, Voltage in the SDG&E/Yuma/CFE Island

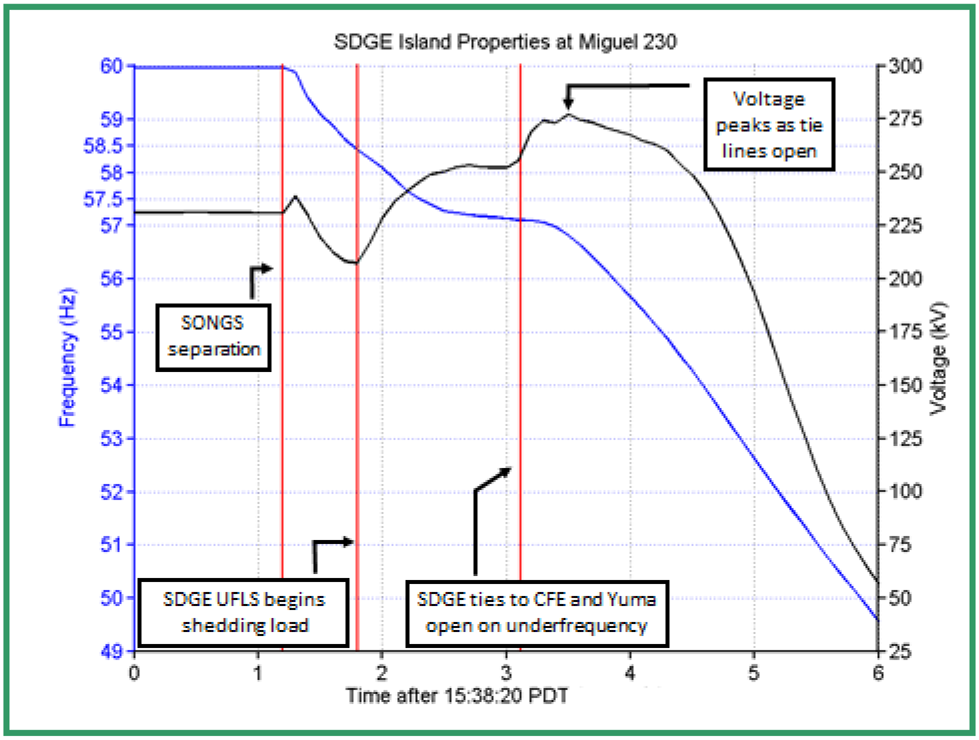
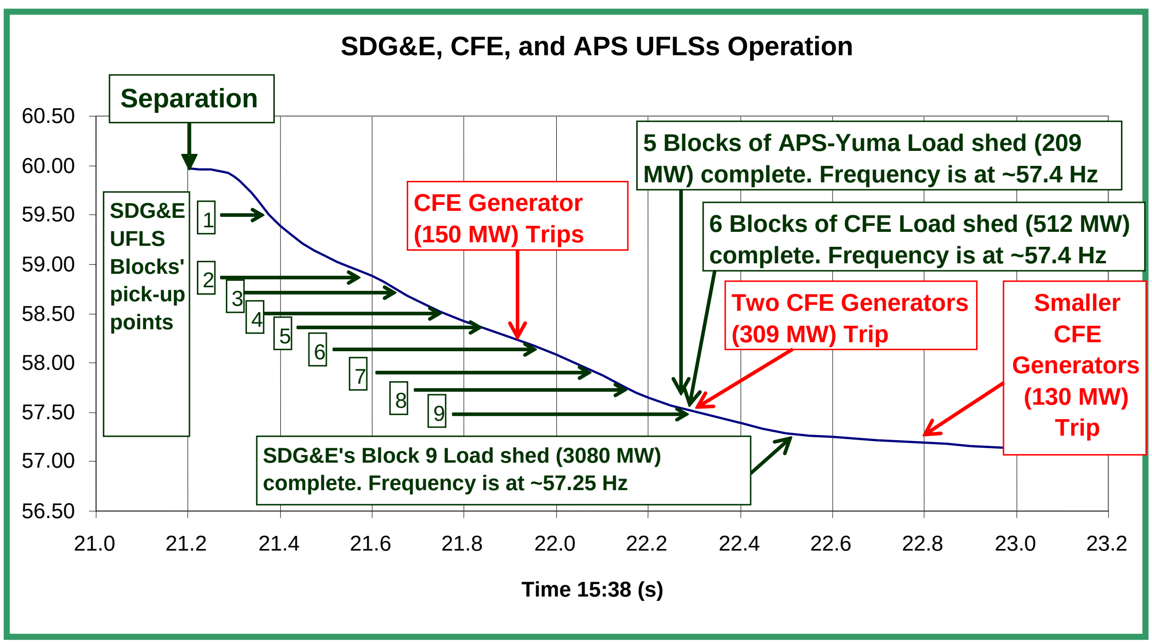


Figure 11: Frequency Performance in the SDG&E/Yuma/CFE Island



The CFE island separated from SDG&E after their only two remaining ties tripped in rapid succession. At 15:38:22.2, the Otay Mesa-Tijuana 230 kV transmission line open-ended at Tijuana in CFE's territory due to underfrequency protection.[55] Less than a second later, at 15:38:23.13, the Imperial Valley-La Rosita 230 kV transmission line open-ended at Imperial Valley in SDG&E's territory by underfrequency protection.[56] According to CFE, its UFLS program was not designed for the operation of a SDG&E/CFE/Yuma island, but for the operation of a "southern WECC island."

The Yuma island separated from SDG&E at 15:38:23.12, when the Imperial Valley-North Gila 500 kV transmission line tripped by underfrequency protection. APS's UFLS operated on 26 out of the 28 feeders in the Yuma area prior to the loss of the local Yucca steam generators that were on line. However, there was insufficient local generation to stabilize the load pocket in Yuma. At 15:38:38, the Yuma island internal units tripped on underfrequency protection.

At about the same time that it separated from CFE and APS's Yuma pocket, SDG&E lost four generating units, totaling 570 MW, due to the generators' underfrequency protection.[57]

Although the SONGS generators remained connected to the SCE side of the switchyard at SONGS, at about 15:38:27.5, or approximately six seconds after the SONGS separation scheme initiated, the SONGS turbines both experienced a brief acceleration in speed and tripped due to turbine control logic. At the same time, local system frequency at SONGS was observed to spike from 59.974 Hz to 61.203 Hz. After the initial impulse caused by the system separation, the frequency in the main body of the Western Interconnection peaked near 60.170 Hz. This can be seen on Figures 12 and 13, on the next page. The turbine trip initiated a reactor shutdown, and the units began coasting down. A little more than a second later, at 15:38:28.963, SONGS Unit 3 electrically disconnected from the system, and less than three seconds after the reactors shut down, at 15:38:30.209, SONGS Unit 2 electrically disconnected from the system.

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[55] The Tijuana end opened instantaneously. Subsequently, the Otay Mesa end of the line in SDG&E's territory opened at 15:38:23.044 by underfrequency protection (with 1-second delay).

[56] The line's underfrequency setting was 57.9 Hz, with 1-second delay. The instantaneous underfrequency protection scheme at La Rosita in CFE's territory failed to operate due to a bad fuse connection.

[57] At 15:38:23.000, the Palomar Energy Center combustion turbines CT1 and CT2 tripped on underfrequency, followed by the heat recovery unit ST at 15:38:23.07 (all set to trip at 57.3 Hz with a 750 millisecond time delay). CT1 was loaded to 160 MW, CT2 was loaded to 165 MW, and ST was loaded to 195 MW at the time of the trips. It is believed that additional unit Goal Line LP, generating 50 MW, tripped around the same time due to a 58 Hz frequency with a 1-second time delay.

Loss of the 2,300 MW of SONGS' generation effectively reduced the loss of load for the main body of the Western Interconnection from a 3,400 MW loss to a net 1,100 MW load loss. This made the recovery from the resulting overfrequency event much easier. The SONGS generators did not lose offsite power because the SONGS switchyard was still connected to the SCE system.

Figure 12 : Frequency Excursion in WECC Interconnection Immediately after the SONGS

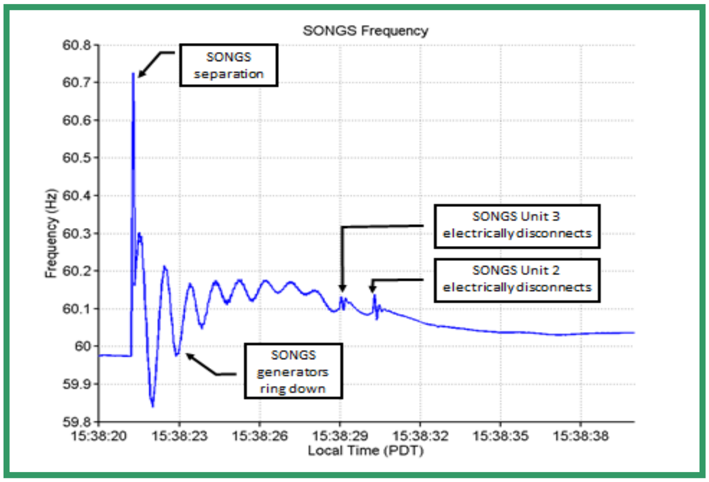
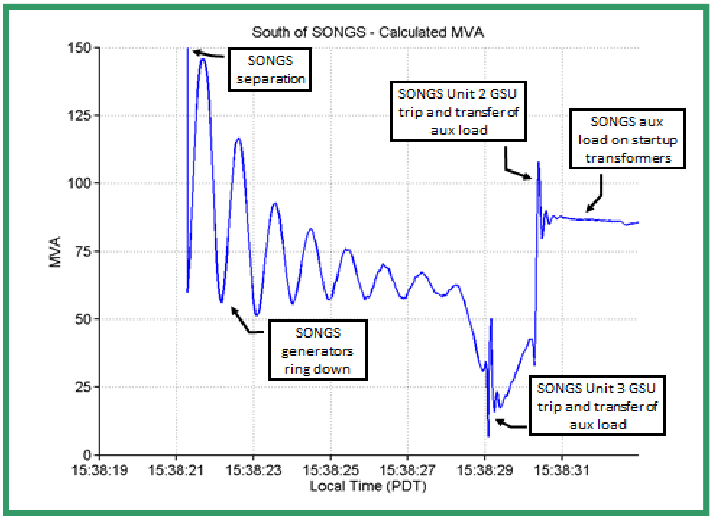


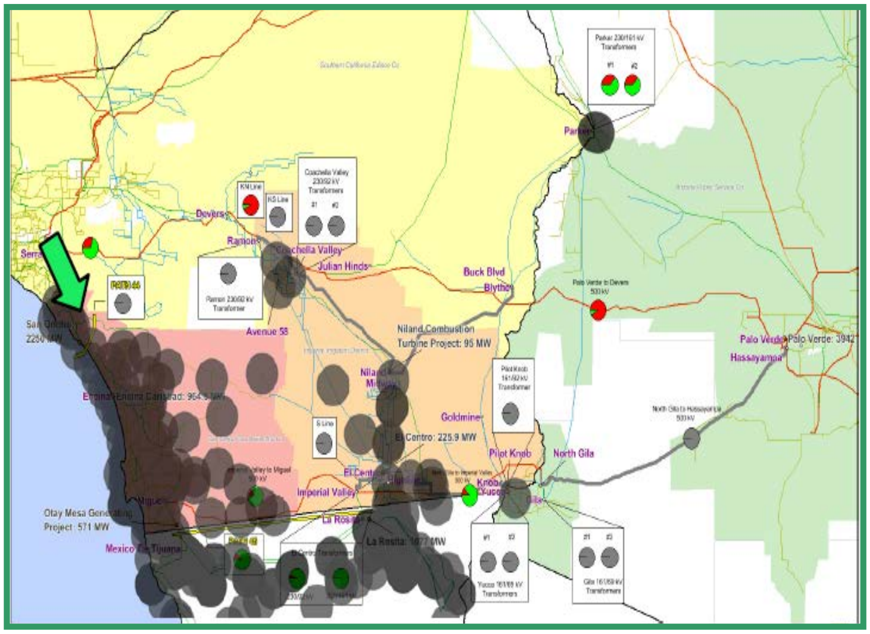
Figure 13: SONGS Generation Trips and Auxiliary Loads Transfer to 230 kV Bus



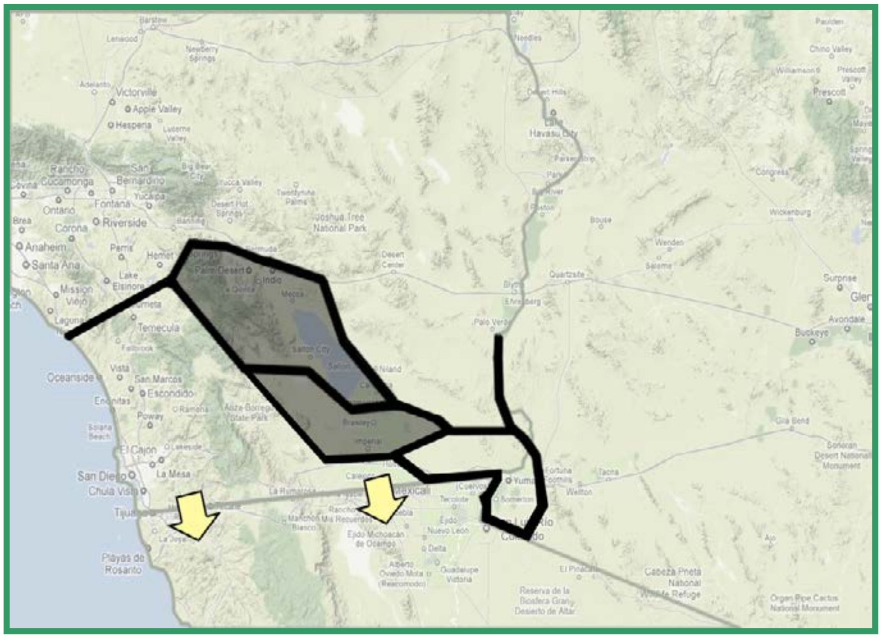
By 15:38:38, the SDG&E, CFE and Yuma islands had all collapsed, leaving approximately 2.7 million customers without power.

Phase 7 Graphics

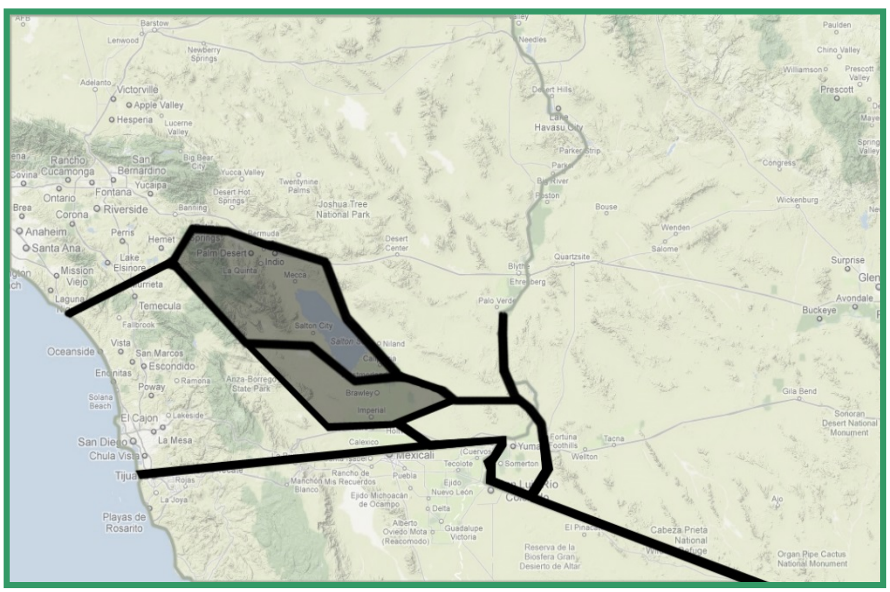
Time: 15:38:30 – The South of SONGS Separation Scheme operates and both SONGS units tripped. (300)



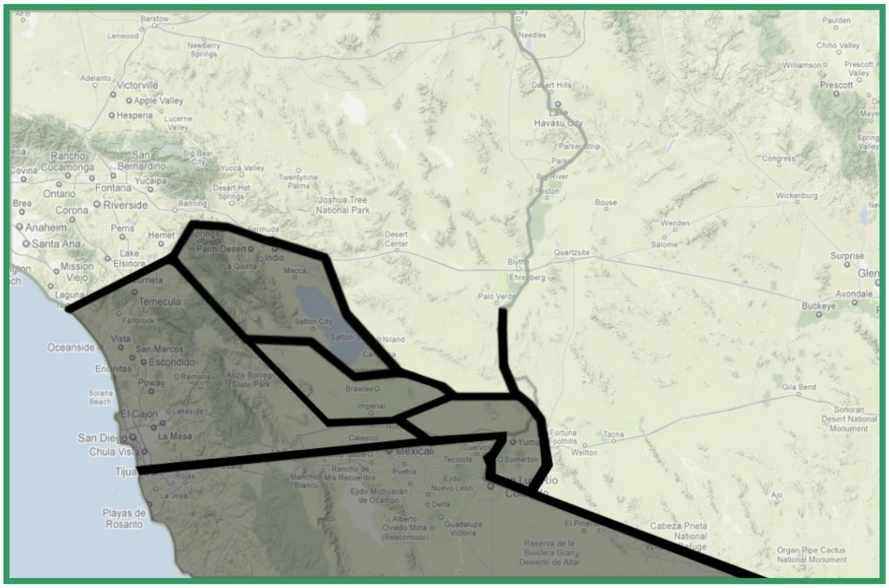
Yuma Separates (Time: 15.38.23.12)



CFE Separates (Time: 15.38.23.13)



SDG&E, CFE, and Yuma Blackout (by 15.38.30)



H. System Restoration

None of the affected entities needed to implement black start plans because they all were able to access sources of power from their own or a neighbor's system that was still energized. The restoration process generally proceeded as expected, and some entities restored load more quickly than they had expected. The following charts indicate how long it took the affected entities to fully restore their lost load, generation, and transmission.

LOAD RESTORATION EFFORTS					
Entities	Demand Interrupted (MW)	Time Until Demand Fully Restored	Date Restored	100 % Demand Restored (hrs)	Number of Customers Affected
SDG&E	4,293	03:23	9/9/11	12	1.4 Million
CFE	2,205	01:37	9/9/11	10	1.1 Million
IID	929	21:40	9/8/11	6	146,000
APS	389	21:12	9/8/11	6	70,000
WALC	74	22:23	9/8/11	6.5	5[58]

58 The majority of WALC's lost load (64 MW) affected APS customers. SCE lost 117 fringe load customers who were served by the SDG&E system.

GENERATION RESTORATION EFFORTS				
Entities	Generation Lost (MW)	Time Generation Restored	Date Restored	Generation Restored (hrs)
SCE	2,428	06:33	9/12/11	87
SDG&E[59]	2,229	06:20	9/10/11	39
CFE	1,915	23:43	9/10/11	56
IID	333	20:42	9/8/11	5
APS	76	20:37	9/8/11	5

TRANSMISSION RESTORATION EFFORTS				
Entities	Final Transmission Restored (kV)	Time Transmission Restored	Date Restored	Transmission Restored (hrs)
IID	230 161	03:37 00:31	9/9/11 9/9/11	12 9
SDG&E	500 230	17:36 03:47	9/8/11 9/9/11	2 12
APS	500	16:51	9/8/11	1.5
WALC	161	17:09	9/8/11	1.5[60]
CFE	230 115	04:03 01:58	9/9/11 9/9/11	12.5 10

59 According to SDG&E, after restoring the SDG&E transmission systems, CAISO took over restoring SDG&E's generation.

60 This represents the time it took WALC to restore its 161/69 kV Gila transformers, however, none of WALC's transmission lines were lost in the outage.

WECC RC could have taken a more active role in coordinating the restoration efforts. WECC RC has the largest area of visibility and more advanced real-time study tools than the TOPs. During a multi-system restoration, issues are likely to arise between neighboring BAs and TOPs that may require either a neutral decision maker, or rapid technical analysis of unplanned system conditions. WECC RC is uniquely situated to provide such assistance. WECC RC should clarify its role, and the real-time information it can provide, in emergency situations like a multi-system restoration. WECC RC should also specifically address the issue of coordination among other functional entities (like BAs and TOPs) in its operating area, outlining the areas of responsibility during system restoration and other emergencies.

The inquiry reviewed recordings and other data about restoration which disclosed the following incidents that could have benefitted from better WECC RC coordination and assistance in real time:

- A 30-minute debate occurred between SCE, which was attempting to provide cranking power to SDG&E to restore SDG&E's system, and the SONGS operators, about the conditions necessary for resetting the SONGS separation scheme lockout relay.
- Recordings showed a lack of clarity among WECC RC, CAISO, and SDG&E about responsibilities for restoration efforts. Among other things, this resulted in a SONGS operator making a unilateral decision to open a circuit breaker on the line responsible for restoring power to SDG&E's system, leaving the line in a less reliable configuration (connected to a single bus).

IV. Causes, Findings, and Recommendations

A. Planning

Next-Day Planning

- **Background**

TOPs are required to perform next-day studies to identify and plan for potential limitations on their system in the day-ahead timeframe, and to coordinate these studies with their neighboring TOPs.[61] These studies provide a proactive mechanism to ensure that the system can be operated reliably and allow time to develop effective operating solutions.[62] These solutions include, among other things, effective control actions needed to return the system to a secure state in anticipated normal and contingency system conditions. The development of these plans in the day-ahead timeframe is critical because it would be nearly impossible, due to the complexity of the BPS, for control room operators to return the system to a secure operating state under stressed conditions without effective action plans developed in advance. The adequacy of next-day studies depends on how extensively and accurately facilities and next-day system conditions are incorporated into the models used for the studies. This includes consideration of a reasonably accurate, current, and complete list of external contingencies that could impact a TOP's system as well as internal contingencies that could impact external SOLs. Consistency of study inputs among all TOPs and BAs is also critical for reliable operation.

The inquiry found that the affected TOPs' and BAs' procedures for conducting next-day studies and models used in these studies vary considerably. As explained more fully below, APS does not conduct next-day studies, relying, instead, on two sets of studies, conducted on a seasonal and annual basis, that consider a list of possible, predetermined contingency scenarios and provide plans to mitigate the contingencies if violated. Meanwhile, IID has a policy of conducting next-day studies each day, but between April and October of 2011, it failed to perform the required studies on a daily basis. All other affected TOPs conduct next-day studies, but they use models that do not adequately reflect next-day operations of facilities in networks external to them. These

[61] *See* NERC Reliability Standard TOP-002-2b R11.

[62] *See, e.g.*, NERC Reliability Standard TOP-002-2b ("Current operations plans and procedures are essential to be prepared for reliable operations, including response for unplanned events.").

TOPs' next-day studies also do not consider a full list of internal and external contingencies that could impose limitations on their daily operations or external operations. Moreover, most of these TOPs' next-day studies do not consider the impact of sub-100 kV facilities on BPS reliability, such as the impact of IID's CV transformers.

WECC RC is the highest level of authority responsible for reliable operation of the BPS in the Western Interconnection, with the authority to prevent or mitigate emergency operating conditions in the next-day and real-time timeframes. As such, WECC RC also conducts next-day studies for the entire Western Interconnection and builds its model from the previous day's peak State Estimator case, which includes all facilities operated at 100 kV and above and some sub-100 kV facilities. WECC RC then incorporates forecast information, which typically includes transmission outages as provided by TOPs, generation outages or derates of 50 MW or greater as provided by TOPs, as well as load forecasts, expected net interchange, and unit commitment forecast data from BAs. While WECC RC has a more extensive representation of facilities throughout the WECC footprint in its model than any individual TOP, it does not necessarily monitor or alarm for certain lower voltage facilities and facilities deemed non-BES that can impact BPS reliability. Moreover, because some of the forecasted information can change between the time the TOPs and BAs provide it to WECC RC and the time WECC RC runs its next-day studies, WECC RC's next-day studies might not accurately reflect next-day operations.

The September 8th event exposed four weaknesses with the foregoing procedures for conducting next-day studies in WECC's region. These weaknesses are detailed in the following four findings. A common theme prevails in all four findings: the affected entities do not accurately account for external next-day operating conditions or potential external contingencies that could impact their systems.

Finding 1 Failure to Conduct and Share Next-Day Studies:

- **Not all of the affected TOPs conduct next-day studies or share them with their neighbors and WECC RC. As a result of failing to exchange studies, on September 8, 2011 TOPs were not alerted to contingencies on neighboring systems that could impact their internal system and the need to plan for such contingencies.**

Recommendation 1:

- **All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied.**

Failure to Conduct Next-Day Studies

APS does not conduct next-day studies. Instead, it relies on two sets of studies, conducted on a seasonal and annual basis, for its daily operations. First, APS uses its summer and winter seasonal studies for the non-WECC Rated Paths within its transmission system. APS performs these studies on a model that it builds from the WECC heavy summer base case. In a coordinated effort with other entities in Arizona, it updates this WECC base case with anticipated loads and resources from the state. APS then adds a detailed representation of the entire state's network, including its own subtransmission system down to the 12 kV distribution system, to finalize the summer model. To create its winter model, APS modifies the summer model with winter peak conditions throughout Arizona.

Once these summer and winter models are complete, APS studies a set of predetermined contingencies, and relies on the results to determine the response of its transmission system to single and multiple contingencies during peak load conditions with planned outages modeled. The studies' list of contingencies is based on past studies, operating experience, and engineering judgment. The studies also establish mitigating measures for contingencies that do not meet loading or voltage guidelines.

Second, APS relies on a single manual, developed annually, as a guide for its daily operations on four Rated Paths within its system. This manual is the result of studies of possible, predetermined contingencies on Rated Paths. The results and operational instructions in this manual are based on seasonal models that APS develops in coordination with four WECC regional study groups, led by CAISO. CAISO first sends a base case to each study group to update with topology changes for the upcoming season. Individual members of each study group also update the model with details from their systems. CAISO then incorporates all of the updates and stresses key Paths in California before sending the model back to the study groups. APS uses this model as a starting point to study the four Rated Paths in its system. APS analyzes the resulting peak-load model using a predetermined set of single and double contingency events that are focused primarily on high-voltage transmission outages to determine required actions to secure the system for the next most critical N-1 event.[63] The manual directs APS to rerate relevant Path(s) and identifies necessary mitigating measures as long as the contingency (or multiple contingency) scenario is included in the manual. The manual, however, may not include a particular contingency (or multiple contingency)

[63] APS's manual covers only 500 kV and 345 kV facilities, and nothing lower.

scenario, or may not accurately reflect the internal and external system topology for the day in question, resulting in the potential for unforeseen circumstances.

Thus, APS uses seasonal studies for non-Rated Paths and the manual for Rated Paths as tools in the day-ahead timeframe, without any additional analysis to validate that the tools remain valid for the next day's specific configuration and operation, such as transmission or generation outages external to APS's footprint that were not anticipated at the time the base seasonal study was performed. APS maintains that these tools are sufficient for day-ahead purposes because they include the most severe contingencies identified in its system. This viewpoint overlooks the purpose of next-day studies—to plan for next-day operations *in light of conditions that change daily*. By relying on tools based on studies conducted on a seasonal and annual basis, APS cannot account for all plausible daily scenarios. For typical days that fall within the boundaries of the underlying studies and analysis, APS's tools may be viable. For atypical days where conditions fall outside the studied boundaries, however, this approach may not be adequate. For example, September 8, 2011, was an atypical day not contemplated by APS's manual, as the manual did not account for various generation outages in effect for maintenance.

Between April and October 2011, IID also did not consistently perform adequate next-day analyses for each day. Although IID had a policy of conducting separate next-day analyses for each new day, it failed to consistently perform the required analyses. Specifically, IID produced a document each new day showing various changes in weather, load and generation forecasts, planned facility outages, potential contingency violations, or mitigation measures for identified contingencies, but did not always perform the underlying power flow studies for each day between April and October 2011. On average, between April 2011 and October 2011 IID actually performed a study no more than two times per week. For the other days, IID simply referenced past studies. For example, it appears that IID did not perform a separate, updated study for September 8, 2011, because the powerflow study case provided for this day does not match the contingency results included in the daily operations guide for the day. In other words, it appears that for September 8, 2011, IID simply changed the forecasted data without actually performing the next-day study. Instead, IID referenced a previous study. The referenced study, however, was not valid because it did not match the load and generation dispatch data for the day, and there were differences in projected overloads reported as potential contingencies. IID's next-day studies were purportedly reviewed by IID for accuracy, but these discrepancies were not identified. IID discovered this issue during the course of the inquiry and is in the process of implementing corrective actions to ensure accurate next-day analyses are completed in the future.

Finally, the inquiry heard on more than one occasion from TOPs, including APS, that WECC RC was responsible for conducting next-day studies or that WECC RC should conduct next-day studies that TOPs are currently responsible for conducting. WECC RC's next-day studies for the entire Interconnection, however, are not intended to substitute for the TOPs' next-day studies of their own systems.

Failure to Effectively Share and Coordinate Next-Day Studies

In addition to finding that not all entities conduct next-day studies, the inquiry found problems with sharing and coordination among the affected TOPs that do conduct such studies. The affected TOPs do not consistently share their studies with neighboring TOPs, BAs, and the RC. TOPs generally provide studies to WECC RC only if the RC identifies an issue in its study and specifically asks to review a TOP's study. In addition, WECC RC's method of sharing its next-day studies with other entities is not effective. Specifically, WECC RC's practice is to share the results of its next-day studies when conditions warrant, or when it receives a request for a study result.[64] WECC RC posts on a secure Internet portal a list of limitations or SOLs identified by its next-day studies for individual TOPs and BAs to view, but it is up to TOPs and BAs to access this list. Also, this list contains only issues that WECC RC deems significant and does not include basic, next-day operating conditions, such as scheduled outages.

One example of the adverse consequences of these sharing and coordination issues relates to the 600-plus MW of TDM generation that was offline for maintenance on September 8th. The TDM generation outage was included in WECC RC's and CAISO's next-day studies, and posted on CAISO's website, but not incorporated into other entities' next-day models and studies.[65] WECC RC receives outage information from TOPs and BAs through its Coordinated Outage System (COS). While TOPs and BAs submit their own information into COS, they cannot access information submitted by others. IID could have benefitted from knowledge of the TDM outages. The TDM units radially connect to the Imperial Valley substation, jointly owned by IID and SDG&E. If the TDM units had been online, they could have mitigated northern IID overloads on the

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[64] *See* WECC Reliability Coordination, Operations Planning, Version 3.0, June 22, 2011, at 6, *available at* http://www.wecc.biz/awareness/Reliability/WECC RC Operating Procedures/WECC RC Operations Planning.pdf.

[65] CAISO knew about the outages because the TDM units participate in the CAISO market. CAISO posts daily outage unit status reports on its public website that provide the best available data at the date and time of the report, for generation units that participate in CAISO's market. These outages are posted at http://www.caiso.com/market/Pages/OutageManagement/UnitStatus.aspx. In CAISO's archives, the TDM units are shown on outage on September 7 and 8, at a minimum. Dispatch details, however, are not included. WECC RC receives CAISO's outage unit status reports daily by email and was aware of the outages. However, IID and APS did not know about the TDM outages.

CV and Ramon transformers that resulted when H-NG tripped. If IID had learned about these outages from WECC RC or CAISO, it could have incorporated the outages in the day-ahead timeframe and dispatched additional generation, or taken other control actions, to compensate for the overloads on its system caused by having these generators offline and the H-NG tripping.

The September 8th event illustrates that conducting next-day studies and sharing the results of such studies are critical to allow TOPs to identify and plan for potential contingencies.

Finding 2 **Lack of Updated External Networks in Next-Day Study Models:**

- **When conducting next-day studies, some affected TOPs use models for external networks that are not updated to reflect next-day operating conditions external to their systems, such as generation schedules and transmission outages. As a result, these TOPs' next-day studies do not adequately predict the impact of external contingencies on their systems or internal contingencies on external systems.**

Recommendation 2:

- **TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.**

As a starting point for their next-day studies, the affected TOPs use models from either a TOP's seasonal base case or the previous day's EMS model, if available. The seasonal base case represents next-day operating conditions internal to the TOPs' systems, but leaves external networks exactly as they were represented in the WECC seasonal base case. The affected TOPs' EMS models sometimes include only one or two buses outside each TOP's internal footprint. Thus, neither type of day-ahead model contains actual day-ahead forecasts of system conditions external to each TOP's system. For example, leading into September 8th, the affected TOPs had limited knowledge of the current status of transmission facilities, expected generation output, and load predictions outside their footprints. Consequently, their next-day studies could not adequately predict the impact of external contingencies on their systems or of internal contingencies on external systems.

IID's next-day study for September 8th illustrates the adverse effects of not accounting for external next-day planned operations. IID used the WECC heavy summer seasonal base case to model external conditions for its next-day study for September 8th. This base case reflects that most external generation is online to meet summer peak loads. A heavy summer base case does not accurately represent a shoulder season day like September 8th. By September, both generation and transmission maintenance had started.

For example, on September 8th TDM generator units in Mexico, totaling more than 600 MW, were offline for maintenance. These units are external to IID and radially connect to IID's jointly owned Imperial Valley substation. When online, this generation can help to mitigate overloads on the CV and Ramon transformers in IID's system. Because IID relied on a heavy summer seasonal model for external networks and did not incorporate any updates about the TDM generation, its next-day study did not reflect the maintenance outage of these units. With the TDM generation incorrectly represented as being online, IID's next-day study did not correctly identify how much the loss of H-NG would overload IID's transformers in its 92 kV system. In fact, IID's next-day study for September 8, 2011, did not show that the loss of H-NG would overload the CV transformers to their trip point.[66] If IID had learned about the TDM outages (whether from CAISO's website or BY some other method) and incorporated the information into its model, it could have dispatched additional generation, adjusted load, or taken other control actions before the loss of H-NG to mitigate such overloading.

As mentioned above, WECC RC receives next-day data from the entities through interfaces such as the COS. WECC RC is well-situated to facilitate data-sharing among the 37 BAs and 53 TOPs in the WECC footprint. Given the large number of BAs and TOPs in the WECC region, some of which are relatively small in size and resources, central coordination and facilitation may be necessary to ensure that all BAs and TOPs accurately reflect next-day operating conditions external to their system.[67] WECC RC has been working to facilitate data sharing by drafting and circulating a universal

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[66] The heavy summer base case has more than 1,000 MW more generation in the affected area than was available on September 8, 2011. In addition to not representing the offline generation, IID's study, by relying on the heavy summer base case, did not accurately reflect the flow on H-NG. The heavy summer base case shows flow on H-NG as 1,118 MW, while actual flow on H-NG at the time of the trip was 1,391 MW.

[67] Under current WECC RC procedures, the RC only shares the results of its operational planning analyses if the results indicate the need for specific operational actions to prevent or mitigate an instance of exceeding an operating limit. WECC Reliability Coordination, Operations Planning, Version 3.0, June 22, 2011, at 6, *available at* http://www.wecc.biz/awareness/Reliability/WECC RC Operating Procedures/WECC RC Operations Planning.pdf.

nondisclosure agreement. As this report was being finalized, less than 30 of the approximately 100 discrete entities within WECC had signed the agreement.[68]

Finding 3 Sub-100 kV Facilities Not Adequately Considered in Next-Day Studies:

- **In conducting next-day studies, some affected TOPs focus primarily on the TOPs' internal SOLs and the need to stay within established Rated Path limits, without adequate consideration of some lower voltage facilities. As a result, these TOPs risk overlooking facilities that may become overloaded and impact the reliability of the BPS. Similarly, the RC does not study sub-100 kV facilities that impact BPS reliability unless it has specifically been alerted to issues with such facilities by individual TOPs or the RC has otherwise identified a particular sub-100 kV facility as affecting the BPS.**

Recommendation 3:

- **TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.**

The September 8th event showed that some sub-100 kV facilities can have significant impacts on BPS reliability, such as causing instability or cascading outages. Yet, it appears that these facilities are not adequately considered in the day-ahead timeframe. For example, IID's 92 kV network runs parallel to two major transmission Paths: (1) Path 44, which connects to the SWPL via the Palo Verde-Devers 500 kV line (part of Path 49) and runs to the north of IID; and (2) the SWPL, which runs to the south of IID. Given the parallel nature of its system, IID's 92 kV system is forced to carry a significant portion of any east-west power flows whenever segments of Path 44 or the SWPL are out of service.

Because none of the affected TOPs, besides IID, considered IID's 92 kV network in their next-day studies, they were not aware how their internal contingencies could affect IID's 92 kV network, or how an overload on IID's 92 kV network could affect their systems. For example, APS does not routinely study IID's lower voltage facilities, including the CV and Ramon transformers, in the day-ahead timeframe. APS uses seasonal studies and its operations manual as its tools in the day-ahead timeframe. While the model used for the seasonal studies physically has IID's 92 kV network represented, neither the model nor the operations manual are used to consider the next day's specific configuration and operation, such as transmission or generation outages external to APS's footprint that were not anticipated at the time the seasonal study and

[68] The agreement does address market concerns by requiring entities who participate in data-sharing to respect the separation of market and operations functions.

manual were updated. As a result, APS was not able to predict what occurred on IID's system—increased flows and overloading on its 92 and 161 kV transformers and transmission lines—when H-NG tripped offline. Similarly, affected TOPs other than IID do not consider in their day-ahead planning how the loss of the CV and Ramon transformers, leading to the S Line RAS operation, could adversely affect their internal systems. Accordingly, TOPs should revise their next-day study practices to account for all facilities, including those operated below 100 kV, that impact BPS reliability.

WECC RC also did not adequately consider sub-100 kV facilities not identified as BES that can have significant impacts on BPS reliability. While WECC RC does model IID's CV transformers in its next-day studies, prior to September 8, 2011, it did not "flag" them in its studies for active monitoring.[69] This means that WECC RC had data showing that the transformers would overload under certain conditions, but the overloads were not identified by alarms to be seen by RC operators. WECC RC did not actively monitor the CV transformers in its next-day studies because they are below 100 kV and IID had not alerted WECC RC to any issues that would warrant monitoring of the transformers. Given the CV transformers' impact on BPS reliability, WECC RC should actively monitor these transformers.[70]

Finding 4 Flawed Process for Estimating Scheduled Interchanges:

- WECC RC's process for estimating scheduled interchanges is not adequate to ensure that such values are accurately reflected in its next-day studies. As a result, its next-day studies may not accurately predict actual power flows and contingency overloads.

Recommendation 4:

- **WECC RC should improve its process for predicting interchanges in the day-ahead timeframe.**

Interchanges are energy transfers that cross BA Areas. Interchanges can affect flows across transmission systems, so forecasting accurate interchanges is important in the day-ahead timeframe to plan for potential overloading. WECC RC's process for estimating scheduled interchanges is not adequate to ensure that the scheduled interchanges incorporated into its next-day studies are accurate. Under this process, by 10:00 AM each day BAs provide WECC RC with all interchanges they have approved for

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[69] To aid in effectively and efficiently processing and analyzing reliability data for the entire Western Interconnection, WECC RC has the option of flagging a subset of facilities for active monitoring in its studies. It has since updated this feature to flag the CV transformers for monitoring.

[70] WECC RC has implemented new procedures since September 8, 2011, to monitor RTCA results for the CV transformers.

the next day. The BAs typically submit this information once per day without any subsequent updates. WECC RC then validates these scheduled interchanges by comparing the values with what the BAs provided the prior day and with what WECC RC's state estimator observed in the prior days and weeks.

The accuracy of interchange data in WECC RC's next-day studies could be improved by allowing for updates closer to real time. BAs' interchange data are likely to change after their 10:00 AM submittal to WECC RC. Some BAs have automated systems, which send updates of interchange data to WECC RC. Most BAs submit the data manually, only once at 10:00 AM. Inclusion of a process or requirement for BAs to update their scheduled interchanges after their 10:00 AM submission would increase the likelihood of accurate interchange data.

The accuracy of interchange data affected WECC RC's next-day study for September 8, 2011. Specifically, the scheduled interchanges reflected in WECC RC's next-day study for September 8, 2011, were not sufficiently accurate to predict that IID's CV 230/92 kV transformers would overload to their trip point upon the loss of H-NG. After the event, WECC RC ran its next-day study using *actual* interchanges, and found that the CV transformers would overload beyond their tripping threshold upon the loss of H-NG. If WECC RC had used more accurate net interchange data and flagged the CV transformers for monitoring, it could have learned of the issues with these transformers and alerted IID or issued directives for control actions to mitigate the situation, such as increasing generation or shedding load.

Seasonal Planning

- ### Background

Following a set of disturbances in the Western Interconnection during the summer of 1996, WECC established a new seasonal planning structure designed to avert system-wide disturbances while maximizing the commercial availability of transmission capacity. This new structure involved the creation of the Operating Transfer Capability Policy Committee (OTCPC). The purpose of the OTCPC was to provide coordinated standard development and determination of seasonal Operating Transfer Capabilities (OTCs), or Operating Transfer Limits,[71] within the Western Interconnection.[72]

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[71] OTCs are now known as SOLs.

[72] The OTCPC itself was abolished and replaced with a new structure in June 2011; however, planning for the seasonal period in which the blackout occurred was performed under the OTCPC structure, so the inquiry's analysis focused on the OTCPC structure.

Among other things, the OTCPC was designed to be responsible for determining which transmission Paths should be studied, facilitating OTC dispute resolution, ensuring that seasonal studies maintain consistent standards and methodologies, and approving seasonal studies of OTC limits. To that end, the OTCPC was charged with reviewing and approving study plans and technical simulation results; developing policies and procedures addressing seasonal OTCs; establishing working groups such as subregional study groups and the Operating Procedures Review Group; addressing OTC seams issues between subregions; and providing technical guidance.

The seasonal study plans that are reviewed and approved by the OTCPC were created by a set of four subregional study groups (sometimes referred to as SRSGs or simply subregions). There were four groups: (1) the California/Mexico Operations Study Subcommittee (OSS); (2) the Northwest Operational Planning Study Group (NOPSG); (3) the Rocky Mountain Subregional Study Group (RMSG); and (4) the Southwest Area Study Group (SASG). The affected entities were members of two of these groups: the OSS (CAISO, SDG&E, SCE, CFE, and IID) and the SASG (APS, WALC).

On an annual basis, each subregional study group reviewed the Paths in its subregion to determine which Paths should be studied and the system conditions under which they should be studied. Then, seasonally, the four subregional study group chairs submitted their recommendations of which Paths to study to the OTCPC for review and approval. Following OTCPC's approval, the studies were performed in accordance with the OTC study process. This process began with establishment of an initial "base case" by WECC staff, with input from representatives of each subregional group. The "base case" is a computer model of projected or starting power system conditions for a specific point in time. For the 2010-2011 planning year, five base cases were used.[73] Once the comments from the four subregional representatives were incorporated, the final cases were made available via WECC's web site for adjustment and modification by subregional members in order to forecast expected seasonal conditions on the system. The subregional members performed their own seasonal studies, and then met to discuss the results. A subregional seasonal planning case was produced on this basis, but no further studies were performed. Subregional seasonal cases were shared among the four subregions via liaisons from the other subregions. No comprehensive WECC-wide Path rating study was prepared on the basis of the four subregional studies.

[73] These included low summer load, high summer load, low winter load, high winter load, and high spring load.

In addition to, and apart from, the seasonal planning studies just described, TOPs also conduct their own seasonal studies focusing on their own internal networks. These internal studies follow a different process from the seasonal Path rating studies, though both begin with the WECC base case. Internal seasonal studies, however, are not aggregated or reviewed at the subregional level. Instead, TOPs generally replace the information from the WECC base case with more accurate and granular detail for their own areas only. Once updated, the TOPs perform contingency analyses for their own internal purposes. They then share with their neighbors the results of these operational studies, which typically contain only the default data from the WECC base case for everything outside of their own areas.

The inquiry identified a number of issues relating to both types of seasonal planning by the affected entities. These issues impaired the accuracy and effectiveness of the seasonal studies by excluding, in various ways, pertinent issues and information that should have been taken into consideration.

Finding 5 Lack of Coordination in Seasonal Planning Process:

- **The seasonal planning process in the WECC region lacks effective coordination. Specifically, the four WECC subregions do not adequately integrate and coordinate studies across the subregions, and no single entity is responsible for ensuring a thorough seasonal planning process. Instead of conducting a full contingency analysis based on all of the subregions' studies, the subregions rely on experience and engineering judgment in choosing which contingencies to discuss. As a result, individual TOPs may not identify contingencies in one subregion that may affect TOPs in the same or another subregion.**

Recommendation 5:

- **WECC RE should ensure better integration and coordination of the various subregions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between subregional studies. Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies.**

No comprehensive WECC-wide seasonal studies are performed. With respect to seasonal Path rating studies, a representative or leader from each subregion adapts the WECC base case on the basis of input from subregional members, and then makes these revised cases available to the other subregional members for review, comment, and approval. The subregional leader then conducts the seasonal studies concentrating only on the rated Paths in the subregion. The results of the seasonal Path rating studies are shared and discussed first among the subregion's members, and then with the other subregions, but neither WECC RE nor the OTCPC performs or mandates any further seasonal studies, and no new WECC-wide seasonal study is performed to reflect the input of all of the subregions. Instead, representatives of the subregional groups gather informally to discuss the results of their seasonal studies and rely on experience and engineering judgment to identify and resolve any issues.

The events of September 8, 2011, illustrate that this process is not adequate: the tripping of one line in a rated Path—H-NG, which is part of Path 49—ultimately led to the tripping of other lines in other rated Paths, including Paths 44 and 45. Focusing exclusively on Path ratings—and solely on a subregional basis—ignores network facilities that can impact rated Paths (and vice-versa) and does not account for the interrelationships of Paths and other facilities across WECC's subregions.

With respect to the internal seasonal studies, there is even less coordination. TOPs generally perform internal seasonal studies using models that include detailed data for their own system, but default to WECC base case data, which may not be sufficiently detailed or updated, for everything else. TOPs perform contingency analysis for their own internal areas using this model. No study is done to identify the impact of external contingencies on the TOP's system, or the impact of the TOP's internal contingencies on the SOLs of other TOPs. TOPs provide the results of their internal seasonal studies to neighboring TOPs for informational purposes, after which those TOPs may or may not provide comments.

In all, this situation indicates that the TOPs' internal seasonal planning studies are too heavily reliant upon the assumptions underlying and reflected in a single WECC base case, and do not consider and study impacts of variations from that base case.

The September 8th event demonstrated one example where better integration of seasonal studies across two subregions is needed. When H-NG (part of Path 49) tripped, approximately 12% of the flow from that line, which is located in the SASG subregion, was transferred across IID's 230/92kV transformers, via the IID 92kV local network to the southern IID 161 kV network, which are all in the OSS subregion. This additional flow on IID's CV transformers ultimately resulted in cascading outages and impacted Paths 44 and 45. The affected entities were unaware of this potential inter-Path impact, because the SASG and OSS studies had not been jointly considered. Moreover, since the subregional studies concentrate only on Path ratings, this flow transfer was not apparent. If the seasonal studies of SASG and OSS had been better coordinated and more rigorously analyzed, the potential for the loss of H-NG to overload IID's 92 kV network could have been identified and mitigation plans developed.

Finding 6 **External and Lower-Voltage Facilities Not Adequately Considered in Seasonal Planning Process:**

- **Seasonal planning studies do not adequately consider all facilities that may affect BPS reliability, including external facilities and lower-voltage facilities.**

Recommendation 6:

- **TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability.**

As noted above, TOPs performing subregional Path rating studies do not sufficiently account for the impact of facilities external to their subregion, or facilities within their subregion that are not part of a rated Path. Moreover, no WECC-wide Path rating study is performed to harmonize and analyze the impact of one subregion on the rest of the subregions.

The problem with this approach is illustrated in the example cited above: The tripping of a part of one rated Path, H-NG, which is part of Path 49, led to the tripping of portions of other rated Paths. The mechanism whereby these other trips were triggered was the transfer of flow across low-voltage (below 100 kV) facilities that were located in a different subregion. Under the approach to Path rating studies in place at the time, it would have been impossible for WECC RE or TOPs to anticipate and study this possibility, because it occurred across subregions, indirectly, via lower-voltage facilities. Even if seasonal Path rating studies had been performed across subregions, these studies would not have anticipated this possibility, unless they also took into account lower-voltage facilities, which they presently do not.

The internal seasonal planning studies of the various TOPs are subject to similar omissions, although these studies encompass more than just the rated Paths and contain more detail than the Path rating studies. The practices of individual TOPs differ, but none contains sufficient detail and accuracy with respect to facilities outside their own footprints, as well as lower-voltage facilities. IID, for example, has explained that it "does not identify or study components outside of the IID territory below 100 kV for impacts on the BPS reliability in its territory," nor does it "identify or study components inside of the IID territory below 100 kV for impacts on the BPS reliability outside of its territory."

Similarly, while CAISO studies in its seasonal planning process "all of the transmission components that it operates, some of which are below 100 kV," it has also acknowledged that it "does not have the necessary information to accurately study transmission components below 100 kV outside of its territory to determine if they have an impact on the BPS reliability in [CAISO's] service territory."

The events of September 8, 2011, demonstrate that sub-100 kV facilities in parallel with BPS systems can have a significant effect on BPS reliability. The loss of H-NG caused the overloading and tripping of both 230/92 kV transformers at CV, which in turn caused another sub-100 kV transformer to trip at Ramon, which led to the cascading outages discussed in detail above. This possibility was not studied as part of the seasonal studies by any of the TOPs, other than IID, because the CV transformers' secondary windings are below 100 kV. The seasonal studies conducted by affected TOPs, other than IID, did not study the impact of the CV transformers. If the CV transformer contingency overloads had been identified as limiting elements in the seasonal plans, the cascading outages might have been avoided or lessened by having pre-contingency mitigation in place, such as increasing generation on IID's 92 kV system.

Finding 7 Failure to Study Multiple Load Levels:

- **TOPs do not always run their individual seasonal planning studies based on the multiple WECC base cases (heavy and light load summer, heavy and light load winter, and heavy spring), but, instead, may focus on only one load level. As a result, contingencies that occur during the shoulder seasons (or other load levels not studied) might be missed.**

Recommendation 7:

- **TOPs should expand the cases on which they run their individual planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high load shoulder periods.**

WECC created five base cases for the 2010-2011 season— heavy and light load summer, heavy and light load winter, and heavy spring—intended to capture the spectrum of possible loading configurations at different times of the year. The inquiry found that some of the affected TOPs deemed it unnecessary to run individual planning studies based on the multiple WECC base cases. Instead, these TOPs identified some subset of these base cases that they concluded were most relevant to their concerns and ran studies based on only that subset of base cases. Some TOPs employed only one base case—the heavy load summer base case—for planning the season during which the September 8, 2011 blackout occurred. By limiting the run of planning studies to a small subset of base cases, TOPs restrict their ability to anticipate and respond to contingencies arising in the context of load levels that vary significantly from those in the subset of base cases upon which their studies were predicated.

As noted above, September 8, 2011 was a very hot day in the region, and scheduled flows in the IID footprint were near record peaks. The high demand on September 8th was indeed similar to what would have been modeled in a heavy load summer seasonal study. The generation picture, however, was very different. By September 8, 2011 generation maintenance—which is not typically scheduled for summer peak days—had begun. The "heavy peak" summer study base cases that were actually used for September 8th therefore had built into them the incorrect assumption that there would be minimal maintenance—i.e., that most generation would be on line—and thus did not account for the normal resumption of facility maintenance in the shoulder season.

If IID's seasonal studies had assumed even a modest decrease in the available generation, they might have enabled IID to anticipate and prevent the events that occurred on its system. IID was unaware of the TDM maintenance outages, but if it had conducted a shoulder season study, it might have been operating in a mode that more accurately reflected actual operating conditions on that day and could have potentially avoided the overloading of CV transformers to the tripping point. This lack of awareness illustrates the risks of not separately modeling the shoulder months such as September, when facility maintenance has begun but demand could remain or become very high. During these times, generation to serve load may come from other areas, changing flow patterns from those that typically occur on a normal summer peak day in which most generation is on line.

Finding 8 Not Sharing Overload Relay Trip Settings:

- **In the seasonal planning process, at least one TOP did not share with neighboring TOPs overload relay trip settings on transformers and transmission lines that impacted external BPS systems.**

Recommendation 8:

- **TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater.**

As discussed in greater detail below, the relay trip settings of IID's CV 230/92 kV transformers were set very low, just above the facilities' emergency rating. These settings effectively meant that IID's system operators had very little time to respond to the overload resulting from the loss of H-NG beyond emergency ratings and could not rely on post-contingency mitigation. If IID's neighbors had been aware of the relay trip settings on these transformers when preparing their seasonal studies, they would have been able to plan for the possibility of the CV transformers tripping at a lower trip point.

As a general matter, TOPs should be aware of the relay trip settings of facilities in neighboring areas that have the potential to impact portions of the BPS within their own areas, regardless of whether or not those facilities have been defined as, or deemed to be, BES facilities. This concern is particularly acute where the overload trip points of the facility in question are set below 150% of their normal rating, or below 115% of their emergency rating, because, as discussed below, such settings sharply limit the amount of time available for operators to implement post-contingency mitigation measures. These settings require that all entities that could be affected are aware and able to implement pre-contingency mitigation.

Near-and Long-Term Planning

- ### Background

TPs and PCs conduct near- and long-term studies to ensure their systems are planned for reliable operation under normal operating conditions. In addition, the system facilities must remain stable in the event of single and multiple contingency scenarios. Near-term studies consider potential contingencies one to five years past the study date, and long-term studies consider potential contingencies six to ten years past the study date. The near- and long-term planning process in the WECC region involves a coordinated effort among individual TPs and PCs at the local level, Subregional Planning Groups (SPGs).[74] at the regional level, and WECC RE at the Interconnection-wide level. It is a multi-step process, performed annually.

First, TPs and PCs submit data about their internal networks to their respective SPG for each horizon year studied (i.e., years one through ten). These data include forecasted load levels and facilities projected to be in or out of service. Also, these data assume peak load conditions and, thus, reflects that most internal generation is online. Second, SPGs add information to these data based on their broad knowledge of planning projects and reliability issues within their respective regions. For example, an SPG

[74] There are five SPGs in the WECC region, each representing a specific area and composed of various members and stakeholders, including individual owners and operators of transmission networks, representatives of local government agencies, and independent developers. SPGs allow for the joint consideration of issues among individual members. APS, IID, and WALC are members of WestConnect, which performs the SPG function in the Southwest region. SDG&E and SCE are members of CAISO, which performs the SPG function in parts of California. The SPGs are involved in near- and long-term planning only and are unrelated to the SRSGs, discussed above, which deal with seasonal planning.

might add data for a particular horizon year based on its knowledge of a merchant generator's desire to connect to the grid. SPGs also consider future projects needed for reliability and the effect of environmental regulations on the future operation of generator units. Third, SPGs merge all of their members' cases to create a regional case. Fourth, WECC RE merges the various regional cases from all the SPGs to create the base case for each horizon year. WECC RE makes these cases available on its website for TPs, PCs, and SPGs to access. Finally, TPs and PCs add their own subtransmission facilities to the base cases to run their near- and long-term studies. TPs and PCs typically choose a list of contingencies to study based on past experience and engineering judgment.

As discussed below, this multi-step process has several shortcomings, which left the affected entities unprepared for the September 8th event.

Finding 9 Gaps in Near- and Long-Term Planning Process:

- **Gaps exist in WECC RE's, TPs' and PCs' processes for conducting near- and long-term planning studies, resulting in a lack of consideration for: (1) critical system conditions; (2) the impact of elements operated at less than 100 kV on BPS reliability; and (3) the interaction of protection systems, including RASs. As a consequence, the affected entities did not identify during the planning process that the loss of a single 500 kV transmission line could potentially cause cascading outages. Planning studies conducted between 2006 and 2011 should have identified the critical conditions that existed on September 8th and proposed appropriate mitigation strategies.**

Recommendation 9:

- **WECC RE should take actions to mitigate these and any other identified gaps in the procedures for conducting near- and long-term planning studies. The September 8th event and other major events should be used to identify shortcomings when developing valid cases over the planning horizon and to identify flaws in the existing planning structure. WECC RE should then propose changes to improve the performance of planning studies on a subregional- and Interconnection-wide basis and ensure a coordinated review of TPs' and PCs' studies. TOPs, TPs and PCs should develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all protection systems, including RASs, Safety Nets (such as the SONGS separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of elements operated at less than 100 kV on BPS reliability.**

The affected entities' near- and long-term planning studies for horizon year 2011 (i.e., the studies conducted in 2001 through 2010) did not identify that the loss of a single 500 kV line in APS's territory would cause cascading outages across the territories of SDG&E, CFE, IID, and WALC. Several gaps in the near- and long-term planning process contributed to these omissions. First, TPs and PCs submit peak load data to

WECC for incorporation into the base case and, thus, the data assume that most internal generation is online to meet peak conditions. As a result, the models for 2011 did not contain accurate, realistic representations of online generation. Running studies under the assumption that most generation is online provided an unrealistic portrayal of system transfers on the day of the event.

Indeed, system transfers following the loss of H-NG were higher than the transfers seen in the base case used for near- and long-term studies. Significant flows from H-NG transferred across IID's and WALC's systems and onto Path 44. Flow on Path 44 increased by approximately 84% following the loss of the line. These large system transfers went undetected in near- and long-term studies, and the affected entities were not alerted to the need to plan for these critical system conditions. To avoid this problem in the future, TPs and PCs should study more generation dispatch scenarios to provide a more realistic projection of system transfers following contingencies.

Second, TPs and PCs do not run a full list of external contingencies during the near- and long-term planning process. Instead, they rely on experience and engineering judgment, focusing on previously identified contingencies. This can be particularly problematic in today's operating environment in which the nature and limitations of the system are rapidly changing. For example, as part of its near- and long-term planning IID studied potential contingencies on four WECC Rated Paths, but did not study the loss of H-NG. As a result, IID was not prepared for the effect on its system when that line tripped. Also, while IID's CV 230/92 kV transformers are included in the base case, some of the affected TPs and PCs did not study the potential loss of these facilities. By not considering a complete list of external contingencies that could impact their systems, TPs' and PCs' studies for horizon year 2011 were not sufficient to identify and plan for the impact of external contingencies on their internal systems or internal contingencies on neighboring systems.

Third, TPs and PCs do not study external subtransmission facilities in the near- and long-term planning process. Individual TPs and PCs add their own subtransmission facilities after the base case has been created by WECC RE, but do not add external subtransmission equipment. If external subtransmission systems were included in the base case, entities could identify the parallel flow on such lower-voltage systems that can result from transmission contingency outages. This consideration is particularly important for lower voltage systems that parallel external high voltage systems. For example, when APS's H-NG tripped, approximately 12% of its flow transferred to IID's 92 kV system. This increased flow and overloading on IID's system had a ripple effect, causing cascading outages throughout neighboring territories. Because the affected entities did not study external subtransmission systems in their near- and long-term studies, they did not identify the potential for overloading on IID's 92 kV system or the impact on their systems from this overloading.

Fourth, TPs and PCs do not sufficiently study the interaction of protection systems in external networks in their near- and long-term planning studies. For example, some of the affected TPs and PCs did not study the interaction between the overload protection on IID's three 230/92 kV transformers, or between the protection on these transformers and the S Line RAS. Based on the pre-event conditions, the loss of one CV transformer would automatically result in the loss of the second, followed automatically by the loss of the Ramon transformer, which in turn, would result in either voltage collapse and load shedding, or overloading on the S Line. The S Line RAS is designed to mitigate overloads by tripping generation in Mexico that supplies power to IID. However, operation in this manner only served to further overload IID and WALC facilities and exacerbate system conditions on the day of the event. The affected entities should have studied the interaction of these schemes to prepare for the impacts on their systems.

Finding 10 Benchmarking WECC Dynamic Models:

- **The inquiry obtained a very good correlation between the simulations and the actual event until the SONGS separation scheme activated. After activation of the scheme, however, neither the tripping of the SONGS units nor the system collapse of SDG&E and CFE could be detected using WECC dynamic models because some of the elements of the event are not explicitly included in those models. Sample simulations of the islanded region showed that by adding known details from the actual event, including UFLS programs and automatic capacitor switching, the simulation and event become more closely aligned following activation of the SONGS separation scheme.**

Recommendation 10:

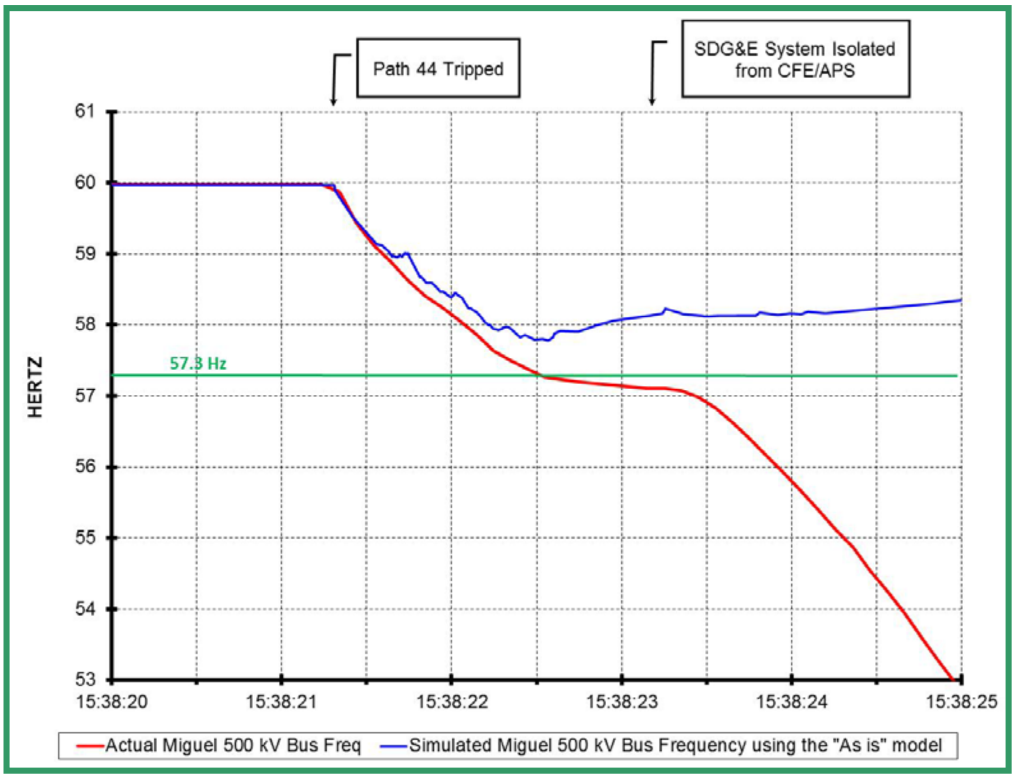
- **WECC dynamic models should be benchmarked by TPs against actual data from the September 8th event to improve their conformity to actual system performance. In particular, improvements to model performance from validation would be helpful in analysis of under and/or over frequency events in the Western Interconnection and the stability of islanding scenarios in the SDG&E and CFE areas.**

The inquiry simulated the dynamic system response of the September 8th event from prior to the loss of H-NG through the separation of Path 44 and the unsuccessful islanding of SDG&E and CFE. The team obtained very good correlation between the simulation model and the actual event until the SONGS separation scheme activated. However, neither the tripping of the SONGS units nor the system collapse of SDG&E and

CFE could be predicted using existing WECC dynamic models entities use to perform near- and long-term planning.

This inability to use the existing system models to reproduce the actual event is also evident in the post-event analysis that was prepared by SDG&E on the effectiveness of UFLS programs following the September 8th event.[75] The SDG&E post-event analysis shows that the UFLS performance should have prevented the SDG&E system from frequency collapse, similar to the "as is" results shown in ***Figure* 14**, below. However, the SDG&E analysis does not explain why the simulation results are so different than the actual system responses—i.e., successful islanding operation versus system collapse.

Figure 14: Actual and Simulated Frequency at Miguel 500 kV Bus



The inquiry's Modeling and Simulation team was able to obtain a simulation more closely aligned with actual measured performance by performing several sensitivity

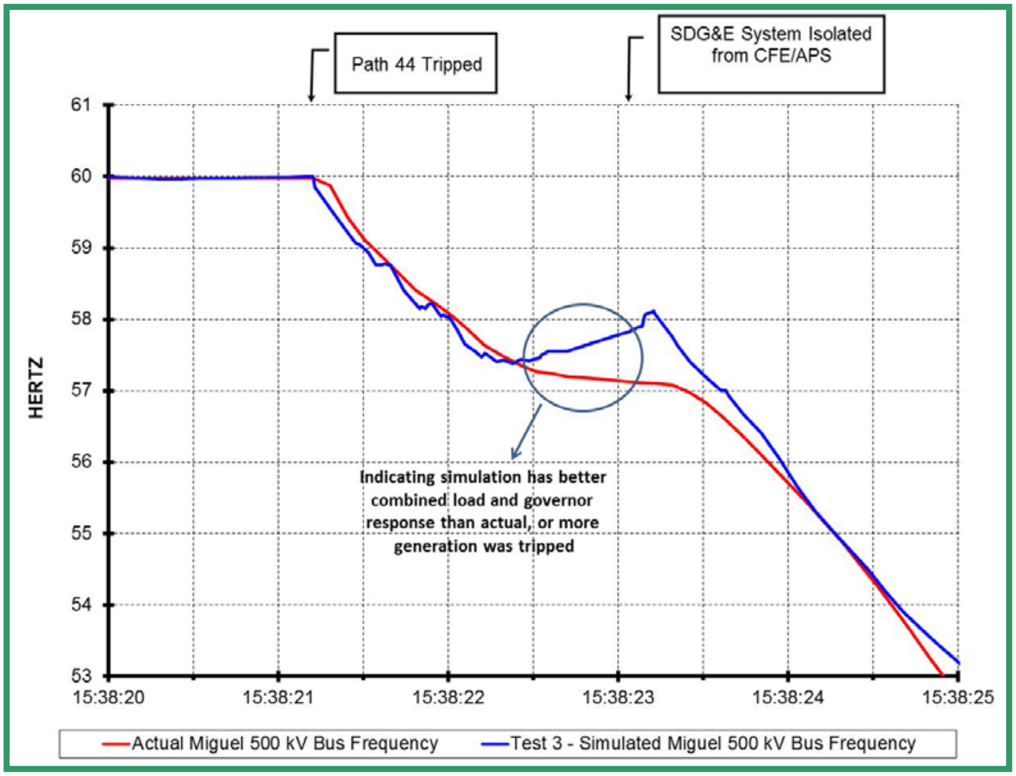
[75] Preliminary Analysis of SDG&E Off-Nominal UFLS Program Effectiveness Following September 8, 2011 Pacific Southwest Event, Performed by SDG&E, December 7, 2011.

studies and adding details from the actual event, including UFLS performance, PMU data, and generation tripped in CFE's and SDG&E's territories. For example, one sensitivity study (referred to here as "Test 3") simulated approximately:

a) 3,080 MW of UFLS in SDG&E 1.3 seconds after Path 44 tripped (compared to 2,760 MW in "as-is" case)
b) 520 MW of UFLS in CFE after Path 44 tripped, but prior to SDG&E separation from CFE/APS (compared to 900 MW modeled in "as-is" case)
c) 589 MW of generation tripped in CFE after Path 44 tripped, but prior to SDG&E separation from CFE/APS (compared to zero in "as-is" case)
d) 1,000 MW of generation tripped in SDG&E immediately after SDG&E separated from CFE/APS (compared to zero in "as-is" case)

***Figure* 15**, below, shows results of "Test 3." As can be seen, this simulation more closely follows the actual event than the "as-is" model used in Figure 14.

Figure 15: Miguel Frequency Actual and Simulated for "Test 3"



The simulation studies explain the ineffectiveness of the UFLS program, despite up to 75% of SDG&E load that was shed within 1.3 seconds of the SONGS separation scheme operating. The simulation analysis confirmed findings in the inquiry's SOE that the frequency collapse was caused by generation trips and UFLS misoperations within

CFE shortly after Path 44's separation, followed by additional generation trips within SDG&E around the time it separated from CFE/APS.

B. Situational Awareness

Background

TOPs, BAs, and RCs have system operators who constantly monitor their networks to maintain situational awareness of system conditions, identify potential system disturbances, and institute mitigating measures, as necessary. The affected entities utilize a range of tools to perform these functions. All of the entities use SCADA systems as their main monitoring tool. SCADA systems typically consist of a central computer that receives information from various RTUs and intelligent electronic devices (IEDs), located throughout the system. SCADA systems provide control center operators with real-time measurements of system conditions and can send alarms to signal a problem.

Most of the affected entities also use several other tools to study and analyze the information received from their SCADA systems. Two of the most important tools are State Estimator and RTCA. State Estimator gathers the available measurements from the SCADA system and calculates estimated real-time values for the whole system. RTCA then takes the information from State Estimator and studies "what if" scenarios. For example, RTCA determines the potential effects of losing a specific facility, such as a generator, transmission line, or transformer, on the rest of the system. In addition to studying the effects of various contingencies, RTCA can prioritize contingencies. It can also provide mitigating actions and send alarms (visual and/or audible) to operators to alert them to potential contingencies.

While most of the affected entities have and use these tools, the inquiry identified several concerns with entities' ability to adequately monitor, identify, and plan for the next most critical contingency in real time. Several areas for improvement are described in the findings below.

PMUs did not play a role in observing the September 8th event in real time, but may prove increasingly important in situational awareness. Of the affected entities, CAISO, SCE, and APS are equipped with PMUs. PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP). Their high sampling speed (up to 30 samples per second) and excellent GPS-based time synchronization offer new granularity in information about voltage phase angles and other grid conditions. PMUs are expected to be used to identify and monitor for grid stress, grid robustness, dangerous oscillations, frequency instability, voltage instability, and reliability margins. While not yet sufficiently integrated to have been used by the affected entities in their control rooms on September 8th, as discussed earlier, PMU data proved valuable in constructing the sequence of events and other post-event analysis.

Finding 11 Lack of Real-Time External Visibility:

- **Affected TOPs have limited real-time visibility outside their systems, typically monitoring only one external bus. As a result, they lack adequate situational awareness of external contingencies that could impact their systems. They also may not fully understand how internal contingencies could affect SOLs in their neighbors' systems.**

Recommendation 11:

- **TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.**

Although all of the affected TOPs use SCADA to monitor their own systems, some TOPs' situational awareness is hindered by their limited visibility into neighboring systems. Some of the affected TOPs' real-time external visibility is limited to one or two buses outside their systems. The September 8, 2011, event demonstrated that more expansive visibility into neighboring systems is necessary for these TOPs to maintain situational awareness of external conditions and contingencies that could impact their systems and internal conditions and contingencies that could impact their neighbors' systems. During the 11-minute time span of the September 8th event, entities observed changes in flows into their systems, but were unable to understand the cause or significance of these changes and lacked sufficient time to take corrective actions. If affected entities had seen and run studies based on real-time external conditions prior to the event, they could have been better prepared to redispatch generation or take other control actions and deal with the impacts when the event started.

IID, for example, is adjacent to APS, and the changes in flows on APS's system, especially on its 500 kV lines, can affect the flows on IID's system and vice versa. Yet, IID's visibility into APS's system is limited to information about the tie line between them. In fact, IID's visibility into all of its neighbors is limited to one or two buses outside its system.[76] As a result, IID did not learn in real-time that H-NG tripped. IID also did not understand prior to the event how changes in flows or the loss of H-NG would affect its system. Immediately after H-NG tripped, IID observed loading on its CV transformers escalate rapidly, but it had not been prepared for this escalation.

If IID had greater visibility into APS's system and IID had an equivalent on its RTCA that modeled the external network using APS's real-time data instead of pseudo-generators modeled at the end of each tie line, IID's RTCA could have more accurately studied the results of a post-contingency loss of H-NG on its system before it occurred. After seeing the more accurate RTCA results, IID could have initiated appropriate control actions before H-NG tripped. Also, having real-time status of the H-NG would have better prepared IID to deal with the effects of its loss in real time.

In addition to IID not having adequate situational awareness of APS's system, the affected TOPs and BAs external to IID were not aware in real time of the effect of the post-contingency loss of IID's three 230/92 kV transformers on their systems. Losses of the CV and Ramon transformers can cause SOL violations on neighboring systems. Indeed, on September 8th, these transformer outages had a significant ripple effect and led to the cascading nature of the event. Yet, entities outside IID's footprint were not prepared for these outages and, except for WECC RC, were unaware of the outages in real time because of a lack of adequate visibility into IID's system. For example, at the time of the event, CAISO's visibility into IID's system stopped at the tie line into IID's El Centro station.

The September 8th event exposed the negative consequences of TOPs having limited external visibility into neighboring systems. Providing TOPs with the ability to observe and model external system conditions and events on a continuous real-time basis will allow them to study and plan for the impact of external conditions and contingencies before it is too late to react, as was the case on September 8th.

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76 IID has made efforts, even before the September 8th event, to receive more data points from adjacent utilities and is currently continuing this effort with all of its neighbors.

Finding 12 Inadequate Real-Time Tools:

- **Affected TOPs' real-time tools are not adequate or, in one case, operational to provide the situational awareness necessary to identify contingencies and reliably operate their systems.**

Recommendation 12:

- TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.

Although many of the affected TOPs have and use real-time tools such as State Estimator and RTCA, some of the tools are not adequate or operational to provide the situational awareness necessary to effectively monitor and operate their systems. Also, some TOPs run or view these tools infrequently, while others run RTCA, for example, every five minutes.

The alarming function on IID's RTCA provides an example of a real-time tool that does not adequately maximize situational awareness capabilities. IID's RTCA does not provide operators with any audible alarms or pop-up visual alerts when an overload is predicted to occur. Instead, IID's RTCA uses color codes on a display that the operator must call up manually to learn of significant potential contingencies. For example, IID's RTCA might show that on the next contingency, a specific element will become overloaded. However, as currently designed, the operator must go to the specific page related to this element to view this result. The result will be color coded on this page, but this code does not function as an alarm.

This design feature of IID's RTCA had negative consequences on the day of the event. Forty-four minutes prior to the loss of H-NG, IID's RTCA results showed that the N-1 contingency loss of the first CV transformer would result in overloading of the second CV transformer to its tripping point. If IID had taken action at this pre-contingency stage, it could have avoided the loss of both transformers. The IID operator, however, did not view the appropriate RTCA display and, therefore, was not alerted to the need to take action. If the operator had reviewed the RTCA results and taken necessary corrective actions, he could have relieved loading on the transformers at this pre-event stage, and thus mitigated the severe effects on the CV transformers that resulted when H-NG tripped.[77]

[77] Since the event, IID has initiated changes to its RTCA program. First, it is working with a vendor to install an audible alarm feature. Second, IID has instructed its operators to constantly leave the RTCA result display screen on, rather than periodically calling it up.

One affected entity, APS, has State Estimator and RTCA capability, but neither tool is operational. As a result, APS has limited capability to monitor and operate its system to withstand potential real-time contingencies. Instead of using RTCA, APS relies on a set of previously studied contingencies and pre-determined plans to mitigate them. These studies are included in a manual that is created annually and usually updated several times a year.[78] By relying on pre-determined studies, APS cannot account and prepare for all potential contingency scenarios in real time. RTCA would provide APS with a more realistic analysis of its next potential contingency because the RTCA analysis is based on real-time conditions, as measured by State Estimator. Without RTCA, APS operators are not fully prepared to identify and plan for the next most critical contingency on its system.

RTCA would have allowed APS operators to study the impact of the loss of its H-NG. Although APS could have studied this contingency in its manual and seasonal studies, it could not have studied it *based on real-time operating conditions* that only State Estimator can provide. For example, APS's manual and seasonal studies did not study the loss of H-NG together with the multiple generator outages that existed on the day of the event.[79] As a result, APS was unprepared for the actual consequences of losing H-NG on September 8, 2011, including overloads on IID's 92 kV system and potential difficulty reclosing H-NG due to large phase angle differences.[80]

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78 APS can also ask WECC RC or an APS engineer for a current-day study, but it usually relies on its manual for operations. APS also relies on WECC RC to notify it of any major post-contingency issues detected by WECC RC's RTCA results, but WECC RC might not consistently and promptly notify individual TOPs of all major issues.

79 APS has indicated that it has had difficulty obtaining generator outage information from other BAs due to market and/or tariff concerns.

80 Prior to the event, APS had been working with a vendor to build its RTCA capability and, since the event; it has accelerated its efforts to make RTCA operational.

Finding 13 Reliance on Post-Contingency Mitigation Plans:

- **One affected TOP operated in an unsecured N-1 state on September 8, 2011, when it relied on post-contingency mitigation plans for its internal contingencies and subsequent overload and tripping, while assuming there would be sufficient time to mitigate the contingencies. Post-contingency mitigation plans are not viable under all circumstances, such as when equipment trips on overload relay protection that prevents operators from taking timely control actions. If this TOP had used pre-contingency measures on September 8th, such as dispatching additional generation, to mitigate first contingency emergency overloads for its internal contingencies, the cascading outages that were triggered by the loss of H-NG might have been avoided with the prevailing system conditions on September 8, 2011.**

Recommendation 13:

- TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency. As part of this review, TOPs should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures.

Before September 8, 2011, IID consistently relied on post-contingency mitigation plans, rather than proactively responding on a pre-contingency basis, for RTCA results showing that the N-1 loss of one CV transformer would result in overloading on the second CV transformer. Post-contingency plans can work to prevent a second contingency as long as operators have sufficient time to take mitigating actions. Post-contingency mitigation is not an appropriate choice for the CV transformers, which are set to trip by overload protection relays without allowing operators enough time to take mitigating actions. Specifically, the transformers' overload protection scheme is set with a thin margin between the emergency rating and the relay trip point. The normal rating of the transformers is 150 MVA, the emergency rating is 165 MVA, and the relay trip point is set at 190.5 MVA, or 127% of the normal rating. Thus, when the transformers reach their emergency rating, operators may have the mistaken belief that they have sufficient time to take mitigating actions, when, in fact, the operators will have very little time before the transformers will trip offline, because they will soon reach the relay trip setting. As shown below, pre-contingency mitigation measures are necessary when operators are faced with settings that leave such little margin between the emergency rating and overload trip point.

On multiple days during the summer of 2011, IID's RTCA results showed that an N-1 contingency tripping of one of the CV transformers would result in overloading on the second transformer. IID continued to operate in this state on multiple days without taking any pre-contingency mitigating actions. For example, IID did not dispatch additional generation on a pre-contingency basis to control the loading on one CV transformer to prevent overloading on the second CV transformer. There were potentially severe consequences of not taking pre-contingency actions. Specifically, IID's next-day study for September 8th detailed that the loss of both CV transformers would overload: (1) IID's Ramon transformer to its trip point; and (2) the S Line, which, in turn, would cause the S Line RAS to trip generation in Mexico that supplies power to the Imperial Valley substation. In short, on multiple days in summer 2011, IID's RTCA results showed that the loss of one CV transformer would overload the second transformer, and IID's next-day study revealed the cascading outages that would stem from the loss of both transformers. Yet, IID did not institute pre-contingency mitigating measures, such as dispatching additional generation.

Instead, IID relied on post-contingency plans. On most days in summer 2011, the level of overloading on the CV transformers gave IID just enough time to successfully use a post-contingency mitigation plan to start generation after the loss of the first transformer to avoid the loss of the second transformer. However, on at least two days observed by the inquiry, a post-contingency plan would not allow the operator enough time to implement necessary procedures to mitigate the problem. On those two days, the loading on both CV transformers was high enough that only pre-contingency mitigation measures could have prevented the loss of the second transformer upon the loss of the first. On the first of those two days, IID was simply fortunate that the N-1 contingency loss of the first transformer never occurred. The second of the two days was September 8, 2011.

Forty-four minutes prior to the loss of H-NG, IID's RTCA results showed that the N-1 contingency loss of the first CV transformer would result in overloading of the second transformer to approximately 139% of its normal rating—leading to the loss of the transformer by relay action. If IID had taken action at this pre-contingency stage, IID might have been able to avoid the loss of both transformers.[81] After H-NG tripped, the relays took less than 40 seconds to trip both CV transformers. Operators had no time to mitigate the overloads before the transformers were removed from service.

[81] The inquiry understands that the IID operator did not see these RTCA results and, thus, would not have known of the need for pre-contingency mitigating measures. There is no indication, however, that IID would have used pre-contingency measures regardless of the results. IID consistently relied on post-contingency measures.

Finding 14 WECC RC Staffing Concerns:

- **WECC RC staffs a total of four operators at any one time to meet the functional requirements of an RC, including continuous monitoring, conducting studies, and giving directives. The September 8th event raises concerns that WECC RC's staffing is not adequate to respond to emergency conditions.**

Recommendation 14:

- **WECC RC should evaluate the effectiveness of its staffing level, training and tools. Based on the results of this evaluation, it should determine what actions are necessary to perform its functions appropriately as the RC and address any identified deficiencies.**

WECC RC performs its reliability coordination functions through two offices. Although each office is capable of monitoring the entire Interconnection, during normal operations the offices have primary responsibility for monitoring different parts of the Western Interconnection. WECC RC's Vancouver, Washington, office is primarily responsible for monitoring the Pacific Northwest (excluding PacifiCorp East), California, and CFE's territory in Mexico. WECC RC's Loveland, Colorado, office is primarily responsible for monitoring the Desert Southwest area, Rocky Mountain area, PacifiCorp's East area, Sierra Pacific Power Company's area, IID's area, and the Los Angeles intermountain area. Each office staffs two on-shift operators at all times. Each center dedicates an operator to the real-time desk (real-time operator) and the other operator to the study desk (study desk operator).

The real-time operator's primary responsibilities include monitoring limits and operating parameters, identifying exceedances, evaluating mitigation plans, and directing corrective actions. The study desk operator's primary responsibilities include monitoring expected post-contingency conditions to identify potential exceedances, evaluating actions being taken, and directing corrective action as necessary. The study desk operator also reviews WECC RC's next-day study for accuracy, conducts real-time studies to evaluate system conditions, and monitors EMS applications, such as RTCA, to identify any performance issues and request corrective actions, as necessary. The real-time operator and study desk operator also have some joint responsibilities, including reporting events that impact the BPS, identifying events or system conditions that require notification to adjacent RCs, and monitoring and testing primary and backup internal communication systems. Through these responsibilities, WECC RC is responsible for the reliable operation of the BPS in the WECC footprint, and it has the ultimate authority to prevent or mitigate emergency operating situations in both next-day and real-time timeframes.

In addition, WECC RC is responsible for providing information to the entities in its footprint, including the 53 TOPs and 37 BAs. Some of this information is provided over the telephone. During the event, in addition to performing the many RC functions they are responsible for performing, the RC operators had to answer phone calls providing or seeking information on the disturbance.

Given WECC RC's responsibility and authority, four total operators—two in each regional office—might not be sufficient to effectively perform its function, particularly during emergency conditions. Several examples from the September 8th event highlight this concern.

First, after the loss of H-NG, many alarms began sounding in WECC RC's control rooms, as voltage dropped and facilities overloaded. With so many alarms sounding in an emergency situation, the real-time operator had a difficult time prioritizing which alarms to monitor. WECC RC has eight unique categories, or "buckets," of alarms within its EMS applications, grouped according to importance. Buckets 1 and 2 contain the highest priority alarms. Bucket 1 includes all 500 and 345 kV circuit breaker status changes, frequency and Path violations, status of generators greater than 50 MW and associated circuit breakers, and critical bus voltages. Bucket 2 includes all 220/230 kV circuit breaker status changes and automatic voltage regulator status.[82] Buckets 3 through 8 include lesser priority items, such as RAS status changes, non-critical bus voltages, and circuit breaker status changes below 220 kV. Operators receive audible alarms for buckets 1 and 2 and typically leave bucket 1's display on the screen constantly and use one other screen to display all other buckets. It is a constant process to continually monitor the alarms, even during normal operating conditions, and it might not be possible for one real-time operator to keep track of and prioritize multiple alarms sounding at once. Also, both operators had numerous phone calls to field from entities throughout the affected areas, reporting and requesting information. Overburdening the real-time operator in this way could undermine his or her ability to perform the critical functions of monitoring system conditions and directing necessary corrective actions. Accordingly, WECC RC should consider whether additional operators are necessary to adequately perform these functions.

A second indication that the current RC staffing levels might not be sufficient came during the September 8th event when the study desk operator had to abandon his duties in order to provide support to the real-time operator by fielding phone calls and monitoring conditions. On this day, the RC operators were able to call for an engineer to

[82] The CV 230/92 kV transformers are included in bucket 2.

conduct some studies. Because the September 8th event occurred during the afternoon, an engineer was available. Finding an engineer to substitute for the study desk operator may not always be so easy. Late at night and early in the morning, no engineers are on duty. That the study desk operator needed to leave his responsibilities to support the real-time operator may indicate that one real-time operator and one study desk operator per office might not be sufficient to fulfill WECC's reliability coordination functions.

Alternatively, additional training and enhanced tools may enable an entity to accomplish more with the same number of personnel. While the inquiry observed a sampling of WECC RC's tools to be adequate during its site visit, WECC RC is in the best position to identify the combination of additional staff, enhanced tools, or training that best addresses the concerns identified by this report.

Finding 15 Failure to Notify WECC RC and Neighboring TOPs Upon Losing RTCA:

- **On September 8, 2011, at least one affected TOP lost the ability to conduct RTCA more than 30 minutes prior to and throughout the course of the event due to the failure of its State Estimator to converge. The entity did not notify WECC RC or any of its neighboring TOPs, preventing this entity from regaining situational awareness.**

Recommendation 15:

- **TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities.**

When entities temporarily lose their RTCA capability due to technical issues, they become blind to the next most severe contingency on their system, and they do not know what pre-contingency measures might be necessary. Thus, when they lose RTCA, they must take immediate action to try to regain their situational awareness. For example, after losing RTCA an entity should contact WECC RC, so the RC can monitor the entity's system and inform it of any significant issues. In such instances, the RC should also notify neighboring entities of any major contingencies that could impact their systems.

Between 13:59 and the start of the event on September 8, 2011, WALC lost its RTCA when its State Estimator stopped solving.[83] As a result, WALC lost its ability to identify and study post-contingency violations and to take pre-contingency mitigating measures, as necessary. When it lost its RTCA, WALC should have contacted WECC RC and asked it to monitor WALC's area. WECC RC could have then notified WALC regarding any significant problems and could have also contacted WALC's neighbors if it

[83] By not solving, or converging, the State Estimator stopped providing estimated values for the system.

learned of any SOLs in WALC that were impacting the neighbors' systems.[84] Prior to the event on September 8, 2011, WALC experienced several post-contingency SOL violations, but, without its RTCA capability, remained unaware of them. WECC RC's RTCA results showed these violations. WALC, however, did not notify WECC RC when it lost RTCA and, thus, WECC RC was unaware that it should notify WALC of the violations. An entity should never be operating in an unknown state, as WALC was when it lacked functional RTCA and State Estimator, and did not ask any other entity to assist it with situational awareness.

Finding 16 Discrepancies Between RTCA and Planning Models:

- **WECC's model used by TOPs to conduct RTCA studies is not consistent with WECC's planning model and produces conflicting solutions.**

Recommendation 16:

- **WECC should ensure consistencies in model parameters between its planning model and its RTCA model and should review all model parameters on a consistent basis to make sure discrepancies do not occur.**

The usefulness of RTCA study results and other real-time studies depend on the models used in the studies. Inaccurate models jeopardize the accuracy of studies, as well as entities' ability to respond appropriately to potential contingencies identified by the studies. The inquiry's simulation of the September 8th event discovered that a discrepancy exists between WECC RC's model used to conduct RTCA studies and the model used for WECC's planning studies. Specifically, the impedance of IID's CV transformers differed by a factor of two between the WECC models. WECC's planning model has an impedance of 0.1 per unit, while WECC RC's RTCA model has an impedance of 0.05 per unit. This difference resulted in an error of approximately 16% in the RTCA model compared to the planning model with respect to loading on the CV transformers.

Although the inquiry did not perform a comprehensive comparison of all parameters in WECC's various models, this discrepancy between the RTCA and planning models on such important facilities calls into question the validity of other parameters in WECC's models.

I. System Analysis

[84] While not at issue in this event, the RC should also notify TOPs if it loses its RTCA, so that TOPs know that the RC is not able to observe their systems.

Consideration of BES Equipment

- ### Background

The BES is generally defined as all facilities operating at voltages above 100 kV, although certain sub-100 kV facilities with a significant impact on the BPS may be considered a part of the BES. Each RE currently determines its specific procedure for determining what is or is not BES. If a facility is not considered BES, relevant TOPs, BAs, and RCs may not study and model the impact of that facility.

Finding 17 Impact of Sub-100 kV Facilities on BPS Reliability:

- **WECC RC and affected TOPs and BAs do not consistently recognize the adverse impact sub-100 kV facilities can have on BPS reliability. As a result, sub-100 kV facilities might not be designated as part of the BES, which can leave entities unable to address the reliability impact they can have in the planning and operations time horizons. If, prior to September 8, 2011, certain sub-100 kV facilities had been designated as part of the BES and, as a result, were incorporated into the TOPs' and RC's planning and operations studies, or otherwise had been incorporated into these studies, cascading outages may have been avoided on the day of the event.**

Recommendation 17:

- **WECC, as the RE, should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems.**

WECC RC, as well as TOPs and BAs impacted by the event, did not consider IID's 92 kV network and facilities (including the CV and Ramon transformers) as BES elements. IID did not reconsider whether the CV and Ramon transformers should be studied like BES facilities even after a draft study sponsored by CFE (and shared with IID) suggested the existence of a through-flow issue between the 500 kV substations at Devers and Imperial Valley, adversely impacting IID's 92 kV network (including the CV and Ramon transformers) during contingencies on BPS systems, including H-NG.[85] Because the Reliability Standards apply to BES facilities, if the CV transformers had been considered BES facilities, IID would have been required to study the impact they could have on BPS reliability.[86] Also, WECC RC and the affected TOPs would likely have included the facilities in their studies and been aware of the impact the loss of H-NG

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[85] *See* CFE's Path 45 Increase Rating Phase 2 Study Report, January 12, 2011, at 19.

[86] *See, e.g.*, NERC Reliability Standard TOP-002-2b R11 (TOPs "shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs").

would have on IID's 92 kV system, as well as the impact various trips within IID's 92 kV system would have on the rest of the BPS. The inquiry determined that, during the event, approximately 12% (168 MW) of the original flow on H-NG was transferred through IID's 92 kV system, making the 92 kV system part of a bulk power path as well as a significant looped transmission facility. The cascading outages that resulted from the loss of H-NG demonstrated the significant potential for IID's 92 kV system, including the CV transformers, to impact BPS reliability.

IROL Derivations

- ### Background

In order to ensure the reliable operation of the BPS, entities are required to identify and plan for IROLs, which are SOLs that, if violated, can cause instability, uncontrolled separation, and cascading outages. Once an IROL is identified, system operators are then required to create plans to mitigate the impact of exceeding such a limit to maintain system reliability.

Finding 18 Failure to Establish Valid SOLs and Identify IROLs:

- **The cascading nature of the event that led to uncontrolled separation of San Diego, IID, Yuma, and CFE indicates that an IROL was violated on September 8, 2011, even though WECC RC did not recognize any IROLs in existence on that day. In addition, the established SOL of 2,200 MW on Path 44 and 1,800 MW on H-NG are invalid for the present infrastructure, as demonstrated by the event.**

Recommendation 18.1:

- **WECC RC should recognize that IROLs do exist on its system and, thus, should study IROLs in the day-ahead timeframe and monitor potential IROL exceedances in real-time.**

Recommendation 18.2:

- **WECC RC should work with TOPs to consider whether any SOLs in the Western Interconnection constitute IROLs. As part of this effort, WECC RC should: (1) work with affected TOPs to consider whether Path 44 and H-NG should be recognized as IROLs; and (2) validate existing SOLs, and ensure that they take into account all transmission and generation facilities and protection systems that impact BPS reliability.**

The NERC Glossary defines an IROL as an SOL that, if violated, could expose a widespread area of the BPS to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the BPS. Each IROL is associated with a maximum time limit (Tv) that the IROL can be exceeded before the risk to the Interconnection or another RC area becomes greater than acceptable. The time limit can vary, but any IROL's Tv must be less than or equal to 30 minutes.[87]

For this event, the loss of H-NG should have been associated with an IROL with a Tv for this N-1 contingency of essentially no minutes, because the cascading from the loss of H-NG began within seconds. However, neither WECC RC nor any of the affected entities have previously identified this IROL. The WECC region historically has maintained an operating philosophy of not recognizing IROLs.[88] Instead, entities in the WECC region believe that as long as they operate within the conditions they have studied, they will not face the risk of IROLs and will not need to calculate IROLs. The September 8th event undermines this philosophy.

Prior to the event, the WECC system was supplying loads in the various balancing authority areas in the range of 85-95% of their recorded peak loads. The power flows on all the Paths in the WECC region were below their maximum ratings and voltages were within acceptable levels. In particular, the two major transmission corridors into the blackout area, namely Path 44 and H-NG, were loaded respectively to 1,302 MW and

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[87] As defined by the NERC Glossary of Terms, an IROL's Tv is "[t]he maximum time that an [IROL] can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each [IROL's] Tv shall be less than or equal to 30 minutes." NERC Glossary of Terms, February 8, 2012, at 26.

[88] As described by WECC in a February 16, 2012 Webinar on its SOL Methodology revision, "***The WECC operating philosophy is to operate only in conditions that have been studied. Therefore, under these normal operating conditions, there are never IROL conditions (only SOLs).*** An IROL condition may be created by the occurrence of one or more unanticipated contingencies. When this occurs, under WECC Reliability Standards, bulk electric system operators are required to resolve the IROL condition within 20 minutes (stability) or 30 minutes (thermal)." http://www.wecc.biz/awareness/Reliability/Documents /SOL Methodology Presentation 02.16.2012.pdf (emphasis in original).

1,372 MW. Compared to their maximum SOL ratings of 2,200 MW and 1,800 MW, these loadings represent 59% and 78% of their maximum ratings—well within current limits. Path 44 and H-NG ratings of 2,200 MW and 1,800 MW may be invalid for the present infrastructure because cascading outages due to a single contingency occurred at loadings well below the SOL ratings.

During the 11-minute disturbance, the single contingency of the sudden loss of H-NG resulted in a series of cascading outages, with multiple elements exceeding their applicable ratings and leading to a widespread blackout of the area.

Accordingly, WECC RC should lead all relevant TOPs in the blackout area to study and report on the appropriateness of identifying Path 44 and H-NG as IROL paths. WECC RC should similarly assess transfer Paths outside this blackout area to ensure that there are no other similar reliability issues in the Western Interconnection. Existing operating processes and procedures should be reviewed to ensure corrective control capabilities are provided to system operators to enable them to return the system to a secure N-1 state as soon as possible, but no longer than 30 minutes following a single contingency.

WECC RC has a proposed new SOL Methodology document (current effective date of June 4, 2012), which acknowledges the need to establish IROLs, and the RC's responsibility to monitor IROLs.[89] It recognizes that "Stability SOLs may qualify as IROLs depending on the potential consequences of exceeding the limit and the impact on BES reliability. WECC RC makes this determination by collaborating with TOPs to understand the nature of the stability SOL, understanding the conditions that result in the establishment of the stability SOL, and determining the BES impacts of exceeding the stability SOL."[90] WECC RC also has a proposed multi-step process for determining whether thermal or voltage SOLs are IROLs. In general, WECC RC will look at whether potential IROLs cause "Widespread Adverse System Impacts," or "potential cascading." "Widespread Adverse System Impacts" is defined as "loading of three or more additional BES Facilities beyond 125% of their applicable emergency thermal Facility Rating, or [t]hree or more additional BES Facilities with bus voltages experiencing voltages less than 90%."[91] "Potential cascading" is defined as "when studies indicate that a

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89 *See* WECC System Operating Limits Methodology for the Operations Horizon, Version 6.1, *available at* http://www.wecc.biz/awareness/Reliability/ WECC RC Operating Procedures/WECC FAC 011-EFFECTIVE DATE 6-4-2012 SOL Methodology for the Operations Horizon.pdf.

90 *Id.* at 5.

91 *Id.* at 6.

contingency results in severe loading on a Facility, triggering a chain reaction of Facility disconnection by relay action, equipment failure, or forced immediate manual disconnection of the Facility (for example, public safety concerns, or no time for the operator to implement mitigation actions)."[92]

Impact of Protection Systems on Event

Protection System Coordination

When an abnormal system condition is detected on the BPS, relay protection systems operate to isolate the problem while causing minimum disturbance to the power system. This requires the relay to be selective in determining which elements to interrupt. The only method of obtaining this selectivity is to perform coordination studies. The inquiry discovered that two TOs did not properly coordinate a protection system and a third TO implemented a protection scheme without performing any coordination studies at all. This lack of coordination of protection systems resulted in circuits unnecessarily being interrupted, which had an undesirable effect on BPS reliability during the September 8th event.

Finding 19 Lack of Coordination of the S Line RAS:

- **Several TOs and TOPs did not properly coordinate a RAS by: (1) not performing coordination studies with the overload protection schemes on the facilities that the S Line RAS is designed to protect; and (2) not assessing the impact of setting relays to trip generation sources and a 230 kV transmission tie line prior to the operation of a single 161/92 kV transformer's overload protection. As a result, BES facilities were isolated in excess of those needed to maintain reliability, with adverse impact on BPS reliability.**

Recommendation 19:

- The TOs and TOPs responsible for design and coordination of the S Line RAS should revisit its design basis and protection settings to ensure coordination with other protection systems in order to prevent adverse impact to the BPS, premature operation, and excessive isolation of facilities. TOs and TOPs should share any changes to the S Line RAS with TPs and PCs so that they can accurately reflect the S Line RAS when planning.

Operation of the S Line RAS isolates facilities beyond what is necessary to ensure reliability. The S Line RAS is a directional overload scheme, located at the Imperial Valley substation, which is jointly owned by SDG&E and IID. The S Line RAS was originally implemented to protect the sole 230/161 kV transformer at El Centro from

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92 *Id.*

overloads due to increased flow on the S Line.[93] At the time, this was the only transfer point from the 230 kV line to the 161 kV system, and subsequently the 92 kV system, in IID's southern area. After implementing this RAS, IID has since installed a 230/92 kV transformer at El Centro, providing another path from the 230 kV system to the lower voltage networks.

IID's current intention for the S Line RAS is to reduce loading on the S Line by tripping generation and, if insufficient to reduce flow, tripping the S Line at Imperial Valley Substation before transformer overload protection operates to trip the 161/92 kV transformer at El Centro. Tripping the S Line before allowing the El Centro 161/92 kV transformer's overload protection to take action effectively results in the removal of the 230 kV source at the El Centro substation, which normally feeds a 230/92 kV transformer and a 230/161 kV transformer. Thus, the design of the S Line RAS intentionally isolates networked BES facilities to mitigate an overload on a non-BES facility (El Centro 161/92 kV transformer) to support reliability of the local system. While this action alone does not constitute miscoordination, proper coordination of a RAS should take into account, through system studies, the potential impact on BPS reliability, including potential interaction with other RASs and protection systems.

During the September 8th event, the S Line RAS operated as designed, in that it tripped when it reached the settings that IID had prescribed. However, if one considers the purpose of the S Line RAS, which was to protect the El Centro transformer from overloads, the S Line RAS operated long before it was needed. At the time that the S Line RAS operated, the El Centro 161/92 transformer was only loaded to 38% of its normal rating, and its overload trip point is 178% of its normal rating. Thus, the El Centro 161/92 transformer could have carried at least four times as much load before the transformer's overload protection system would have operated. Even though the El Centro transformer that the S Line RAS was designed to protect was nowhere near overloading, the S Line RAS tripped important generation and a 230 kV line. This calls into question the coordination of the S Line RAS with the transformer overload protection systems at El Centro.

IID provided SDG&E with the S Line RAS settings to implement. IID did not perform any studies to coordinate the S Line RAS with IID's protection systems. SDG&E did some studies to verify that the RAS coordinated with SDG&E's protection systems. There is no indication that the S Line RAS was coordinated with IID's transformer

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[93] The S Line RAS also serves as secondary protection for other IID facilities if a RAS on the Imperial Valley to Miguel 500 kV line fails to operate.

overload protection at the El Centro station at which the S Line terminates. At a minimum, IID, SDG&E and CAISO (as the TOP for SDG&E) should work together to ensure the proper coordination of the S Line RAS.

To make matters worse, during the September 8th event, San Diego was relying on generation at Imperial Valley from the south when the S Line RAS tripped that generation. Loss of the Imperial Valley generation caused San Diego to pull even more power from the north, increasing the loading on Path 44 and causing the SONGS separation scheme to further exceed its trip point. If not tripped by the S Line RAS, generation at Imperial Valley could have helped SDG&E survive after the operation of the SONGS separation scheme. The inquiry's simulation showed that, had the S Line RAS tripped only the S Line without tripping the generation, the SONGS separation scheme would not have operated, and only IID would have lost power.[94]

Finding 20 **Lack of Coordination of the SONGS Separation Scheme:**

- **SCE did not coordinate the SONGS separation scheme with other protection systems, including protection and turbine control systems on the two SONGS generators. As a result, SCE did not realize that Units 2 and 3 at SONGS would trip after operation of the separation scheme.**

Recommendation 20:

- **SCE should ensure that the SONGS separation scheme is coordinated with other protection schemes, such as the generation protection and turbine control systems on the units at SONGS and UFLS schemes.**

SCE, the TO and TOP of the SONGS separation scheme, did not perform any protection system coordination studies for the separation scheme it implemented at SONGS. The scheme is intended to isolate five 230 kV lines simultaneously if its preset value is exceeded for a sustained period. If SCE had coordinated the separation scheme with other protection and generation control systems at SONGS, it may have recognized the potential for the operation of the SONGS separation scheme to cause the SONGS generators to trip. Coordination in this context requires system studies to assess the impact of operation of the RAS on the power system, including potential interaction with other RASs and protection systems, such as UFLS schemes.

In addition to the consequences at SONGS itself, the lack of coordination of the systems means that, when the scheme operates, the system enters an unknown state.

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[94] *See* footnote 53.

During the event, the operation of the protection scheme significantly contributed to the blackout of SDG&E, CFE, and Yuma—an effect neither coordinated nor adequately studied prior to the event. The inquiry's simulation indicates that SDG&E, CFE and, Yuma would not have been blacked out if the SONGS separation scheme had not operated, with limited impact to the rest of the Western Interconnection.

Finding 21 Effect of SONGS Separation Scheme on SONGS Units:

- **The SONGS units tripped due to their turbine control systems detecting unacceptable acceleration following operation of the SONGS separation scheme.**

Recommendation 21:

- **GOs and GOPs should evaluate the sensitivity of the acceleration control functions in turbine control systems to verify that transient perturbations or fault conditions in the transmission system resulting in unit acceleration will not result in unit trip without allowing time for protective devices to clear the fault on the transmission system.**

When the SONGS separation scheme operated, turbines at SONGS began to accelerate in excess of their control system setting causing both units to trip offline. The tripping of the SONGS units in this manner raises questions about the sensitivity of the turbine control system's settings. The units are expected to withstand severe faults on the transmission system and allow the transmission protection systems to operate without the generators tripping offline. The coordination required for this protection is not a traditional relay-to-relay coordination; rather, the setting for the acceleration function should be coordinated with capabilities of the turbine and with the system response anticipated following operation of transmission protection systems for faults under various system conditions. The setting should also be coordinated with the system response following operation of the SONGS separation scheme. Had the turbine control system acceleration function been coordinated in this manner, the trip of the units may have been avoided.

Protection System Studies

Finding 22 Lack of Review and Studying Impact of SPSs:

- **Although WECC equates SPSs with RASs, prior to October 1, 2011, WECC's definition of RAS excluded many protection systems that would be included within NERC's definition of SPS. As a result, WECC did not review and assess all NERC-defined SPSs in its region, and WECC's TOPs did not perform the required review and assessment of all NERC-defined SPSs in their areas.**

Recommendation 22:

- **WECC RE, along with TOs, GOs, and Distribution Providers (DPs), should periodically review the purpose and impact of RASs, including Safety Nets and Local Area Protection Schemes, to ensure they are properly classified, are still necessary, serve their intended purposes, are coordinated properly with other protection systems, and do not have unintended consequences on reliability. WECC RE and the appropriate TOPs should promptly conduct these reviews for the SONGS separation scheme and the S Line RAS.**

The NERC definition of an SPS concludes with "Also called Remedial Action Scheme."[95] This implies that all SPSs are RASs and vice versa, but prior to October 1, 2011, the WECC region did not equate SPSs with RASs.[96] WECC created four classifications of protection systems that fall under the NERC definition of SPS, and, instead of including all of these classifications in the RAS definition, WECC only identified a subset of those protection systems as RASs. Safety Nets, Wide Area Protection Systems (WAPS), and Local Area Protection Systems (LAPS) were excluded from the WECC definition of a RAS even though they are SPSs as defined by NERC.

For example, SCE did not study the impact of the SONGS separation scheme on BPS reliability because it believed, by classifying this scheme as a Safety Net, that it was not required to be studied. SCE also did not submit the separation scheme to WECC for review by the Remedial Action Scheme Reliability Subcommittee (RASRS). The inquiry determined that the SONGS separation scheme is indeed an SPS/RAS as defined by NERC, because it altered the BPS configuration by separating Path 44 and redistributing generation in the absence of any faulted equipment. WECC, SDG&E, and SCE did not study the impact that the SONGS separation scheme could have on BPS reliability and,

95 NERC Glossary of Terms, February 8, 2012, at 46.

96 On October 1, 2011, WECC revised its definition of RAS to include Safety Nets and Local Area Protection Schemes.

thus, were unaware of its severe impact on the BPS when the scheme operated: blacking out SDG&E and CFE and leading to the loss of the SONGS generators.

Another protection system that did not get the necessary scrutiny due to WECC's narrow definition of RAS was the S Line RAS. The S Line is a 230 kV transmission line that serves as a major tie between SDG&E & IID. It runs from IID's and SDG&E's jointly owned Imperial Valley station on one end to IID's El Centro station on the other. The S Line RAS, as IID and SDG&E called it, was classified as a LAPS by WECC, which called it the "S Line Scheme." Thus, the RAS received no periodic assessments. Like the SONGS scheme, the S Line RAS appears to be a SPS/RAS as defined by NERC, because it is an automatic protection system that took action other than isolating a faulted facility by tripping generation in Mexico for loading on a tie line between SDG&E and IID.

The S Line RAS was implemented for two reasons: (1) to protect IID's system from overload during an N-2 event at SDG&E's Miguel substation; and (2) to protect IID's lone 230/161kV transformer at El Centro from overloads due to generation additions at Imperial Valley substation. The inquiry questions whether the scheme is still necessary, as both of the concerns that originally triggered installation of the S Line RAS have been mitigated. IID added a new transformer bank at El Centro, mitigating the concern for overloads on the 230/161kV transformer. Also, reconfigurations at Miguel along with the modifications to a RAS at Miguel have mitigated the concern of adverse effects on IID's system as a result of an N-2 event at Miguel. Since LAPSs are not periodically reviewed, the arguably outdated S Line RAS was still active during the September 8th event, and its operation contributed to IID's uncontrolled separation and the operation of the SONGS separation scheme by tripping over 400 MW of generation before the S Line itself tripped. At a minimum, SDG&E, IID and CAISO should participate in the review of the S Line RAS.

The SPSs that operated during the event suggest that WECC's previous exclusion of certain NERC-defined SPSs from WECC's RAS definition had an adverse impact on BPS reliability.

Finding 23 Effect of Inadvertent Operation of SONGS Separation Scheme on BPS Reliability:

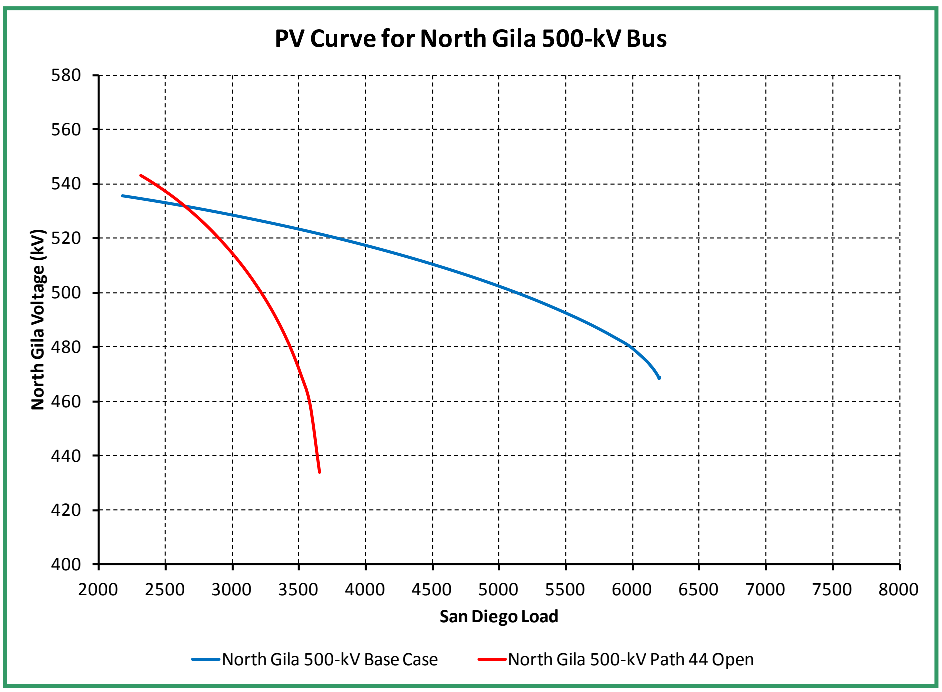
- **The inquiry's simulation of the event shows that the inadvertent operation of the SONGS separation scheme under normal system operations could lead to a voltage collapse and blackout in the SDG&E areas under certain high load conditions.**

Recommendation 23:

- **CAISO and SCE should promptly verify that the inadvertent operation of the SONGS separation scheme does not pose an unacceptable risk to BPS reliability. Until this verification can be completed, they should consider all actions to minimize this risk, up to and including temporarily removing the SONGS separation scheme from service.**

The inquiry conducted a simulation to evaluate what would happen if the SONGS separation scheme inadvertently operated during normal system operations (e.g., in the absence of any outages, overloads, or SOL violations). Based on this simulation, the inquiry determined that under certain high load conditions, the operation of the scheme could result in voltage collapse and a blackout in SDG&E's and CFE's territories. The inquiry conducted a voltage stability study using a Power-Voltage (P-V) curve to estimate the amount of SDG&E load that could reliably be supplied after an inadvertent operation of the SONGS separation scheme. The P-V curve below in ***Figure* 16** demonstrates that such operation would lead to a voltage collapse and a blackout in the SDG&E and CFE territories under certain high load conditions.

Figure 16: PV Curve for North Gila 500 kV Bus



Specifically, the system is most likely to collapse when the SDG&E load exceeds 3,500 MW. In 2010, SDG&E's load exceeded this amount for 851 hours,[97] meaning that the system was exposed to a potential blackout for approximately 10% of the year. This shows the potential risk to BPS reliability during normal system operations as a result of the inadvertent operation of the SONGS separation scheme. Accordingly, given the lack of studies done on the scheme, the inquiry recommends that the inadvertent operation of the SONGS separation scheme be reviewed promptly to ensure it does not pose an unacceptable risk to BPS reliability. Until this verification can be completed, CAISO and SCE should consider all actions needed to minimize this risk, up to and including temporarily removing the scheme from service.

Moreover, if SCE and CAISO were to decide to temporarily remove the scheme from the service, the inquiry does not believe that BPS reliability would be jeopardized. Indeed, inquiry simulations conducted for the day of the event show that if the scheme had not operated, the system, with the exception of collapses in the IID and Yuma areas, would have stabilized with minor overloads in the area around SONGS, acceptable voltages in the SDG&E area, and sufficient reactive margins in the critical portion of SCE's system.

Finding 24 Not Recognizing Relay Settings When Establishing SOLs:

- **An affected TO did not properly establish the SOL for two transformers, as the SOL did not recognize that the most limiting elements (protective relays) were set to trip below the established emergency rating. As a result, the transformers tripped prior to the facilities being loaded to their emergency ratings during the restoration process, which delayed the restoration of power to the Yuma load pocket.**

Recommendation 24:

- **TOs should reevaluate their facility ratings methodologies and implementation of the methodologies to ensure that their ratings are equal to the most limiting piece of equipment, *including relay settings*. No relay settings should be set below a facility's emergency rating. When the relay setting is determined to be the most limiting piece of equipment, consideration should be given to reviewing the setting to ensure that it does not unnecessarily restrict the transmission loadability.**

TOs are required to designate and share their facilities' SOLs. An SOL is the value that satisfies the most limiting element of a facility beyond which the system

[97] SDG&E Annual Electric Balancing Authority Area and Planning, FERC Form No. 714 (2010).

cannot operate reliably. The inquiry's relay loadability calculations show that APS failed to properly establish the SOL for two of its 500/69 kV transformers in North Gila, because the transformers' relay loadability or load limit was actually set below their emergency ratings. A facility cannot operate above its relay load limit, as operation in excess of a load limit results in the facility being removed from service. Thus, these settings prevented the TOP from taking advantage of the short term emergency ratings identified by the transformers' SOLs. These settings resulted in difficulties restoring power to the Yuma load pocket, as operators believed they could load the transformers up to their emergency rating. Instead, the transformers tripped below the emergency rating, delaying the restoration of power to Yuma.

If the SOL derivation had considered the transformer relay load limit, the TO could have (1) provided an SOL that accurately reflected the relay load limit so the system operator could have limited the transformer loading appropriately, or (2) reviewed the relay load limit to determine whether it unnecessarily limited the transformer loadability, and if so, raised the transformer relay setting threshold above the transformer emergency rating while coordinating the setting with the transformer short-time thermal capability.

Load-Responsive Phase Protection Systems Set Too Close to Normal or Emergency Ratings

BES facilities at a minimum are required to have normal and emergency ratings. The normal rating is a continuous rating or a rating that a facility can be operated to on a daily basis that specifies the amount of electrical loading a facility can support. The emergency rating specifies the level of electrical loading a facility can support for a finite period of time. Operating a facility beyond its normal and/or emergency rating for an extended period of time will expose certain equipment in that facility to the risk of thermal damage. In order to prevent thermal damage to facilities, some TOs implement overload protection systems that are designed to automatically isolate the facilities if operated beyond their emergency rating.

A problem arises when overload protection systems are set in close proximity to a facility's normal or emergency ratings. Setting the overload protection close to the normal or emergency ratings restricts facility loading and prevents operators from having sufficient time to take remedial action to mitigate an overload before the facility is automatically isolated by the overload protection system.[98] As the Commission stated

[98] NERC Reliability Standard PRC-023-1 R1.11 provides the following guidance on setting of overload protection systems on transformers: "Set the relays to allow the transformer to be operated at an overload level of at least

in Order No. 733, "manual mitigation of thermal overloads is best left to system operators, who can take appropriate actions to support Reliable Operation of the Bulk-Power System."[99] Protective relay settings limited transmission loadability with extremely conservative overload protection settings, resulting in cascading outages during the September 8th event. These settings resulted in facilities being automatically removed from service by relays before operators had an opportunity to take remedial action.

Finding 25 Margin Between Overload Relay Protection Settings and Emergency Rating:

- **Some affected TOs set overload relay protection settings on transformers just above the transformers' emergency rating, resulting in facilities being automatically removed from service before TOPs have sufficient time to take control actions to mitigate the resulting overloads. One TO in particular set its transformers' overload protection schemes with such narrow margins between the emergency ratings and the relay trip settings that the protective relays tripped the transformers following an N-1 contingency.**

Recommendation 25:

- **TOs should review their transformers' overload protection relay settings with their TOPs to ensure appropriate margins between relay settings and emergency ratings developed by TOPs. For example, TOs could consider using the settings of Reliability Standard PRC-023-1 R.1.11 even for those transformers not classified as BES. PRC-023-1 R.1.11 requires relays to be set to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater.**

Relay loadability calculations indicate that the relay settings on a number of transmission facilities limited transmission loadability to slightly above the emergency rating. For example, the relays on IID's CV transformers were set to trip at 127% of their normal rating. The parallel CV transformers were loaded to 130%, which was above their 127% overload relay trip point, immediately after the loss of H-NG. Both transformers tripped less than 40 seconds later. If the transformers' overload trip point had been in accordance with PRC-023-1 R.1.11, the trip point would not have been exceeded immediately after the loss of the H-NG, and IID operators might have had time to take actions to prevent cascading.[100]

150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater."

[99] *Transmission Relay Loadability Reliability Standard*, 130 FERC ¶ 61,221, at P 212 (2010).

[100] IID originally used conservative settings because the CV transformers are rare, expensive, load-serving transformers. IID has indicated, however, that it will increase the overload relay settings on the CV transformers

During the September 8th event, IID was unaware that the overload relay setting for the Ramon 230/92 kV transformer had been mistakenly set at 207% of its normal rating. IID intended the Ramon transformer to have been set to trip at 120% of its normal rating. After the event, IID reduced the Ramon transformer's trip setting from 207% to 120%, making it more likely to trip during high-loading conditions or conditions similar to those that precipitated the blackout, decreasing the opportunity for its operators to take mitigating actions during such conditions. This setting actually increased the risk of future cascading outages like the one which occurred on September 8, 2011.

Finding 26 Relay Settings and Proximity to Emergency Ratings:

- **Some TOs set relays to isolate facilities for loading conditions slightly above their thirty minute emergency ratings. As a result, several transmission lines and transformers tripped within seconds of exceeding their emergency ratings, leaving TOPs insufficient time to mitigate overloads.**

Recommendation 26:

- **TOs should evaluate load responsive relays on transmission lines and transformers to determine if the settings can be raised to provide more time for TOPs to take manual action to mitigate overloads that are within the short-time thermal capability of the equipment instead of allowing relays to prematurely isolate the transmission lines. If the settings cannot be raised to allow more time for TOPs to take manual action, TOPs must ensure that the settings are taken into account in developing facility ratings and that automatic isolation does not result in cascading outages.**

In addition to the problematic protection settings of the CV transformers, which precipitated the cascade, the inquiry discovered that several other facilities, including a number of IID's 161 kV transmission lines and two of WALC's 161/69 kV transformers, had relay protection settings which were only slightly above those facilities' emergency ratings. These conservative settings severely limited TOPs' response time before the facilities were isolated, preventing the operators from taking effective mitigating action against the cascade. While the inquiry did not determine whether less conservative relay settings on these other facilities would have mitigated the cascade, the applied settings nevertheless do not leave operators sufficient time to take mitigating steps to prevent or ameliorate the consequences of future events.

Angular Separation

to 150% of their normal rating, and will relocate an additional 230/92 kV transformer from another substation to CV.

When a transmission line trips or goes out of service, the phase angle will generally increase between its two terminal points. When angle differences become large, facilities connected to the system can lose synchronization, causing the system to become unstable. Also, if the phase angle is too large, closing the line breaker back into service with a large angle difference may result in damage to nearby generator turbine shafts, and the resulting power swings and oscillations could lead to system instability or collapse. To enable successful reclosing, studies should be run to determine the maximum phase angle difference allowable for a line to be closed back in and safeguards be put into place to prevent reclosure with excessive phase angle difference. Should the phase angle difference exceed the established limit, generation or load must be adjusted to reduce it to the level that allows the line to be closed.

Finding 27 Phase Angle Difference Following Loss of Transmission Line:

- **A TOP did not have tools in place to determine the phase angle difference between the two terminals of its 500 kV line after the line tripped. Yet, it informed the RC and another TOP that the line would be restored quickly, when, in fact, this could not have been accomplished.**

Recommendation 27:

- **TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences. TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day contingency analyses that address the angular differences across opened system elements.**

The inquiry's simulation shows that after H-NG tripped, the voltage phase angle between the two terminals increased from 20 degrees to approximately 72 degrees. On the day of the event, APS's synchro-check relay was set at 60 degrees,[101] meaning APS would not have been able to reclose H-NG until it reduced the phase angle difference from 72 to 60 degrees, or changed the relay setting to allow the breaker to close. Specifically, the 60 degree setting would not have allowed APS to reclose H-NG until appropriate generation on both sides of North Gila was dispatched or load reductions in the areas west of North Gila were implemented to reduce the difference of the voltage phase angle to 60 degrees.

[101] Based on additional studies, APS has since determined the maximum settings on its synchro-check relay at North Gila to allow a maximum phase angle difference of 75 degrees to reclose a line. To add margin, APS has implemented the relay setting at 70 degrees.

Although APS operators are trained to effectively respond to phase angle differences,[102] APS currently lacks the tools necessary to determine phase angle differences following the loss of a transmission line until the line is reenergized.[103] The training, therefore, does little good if the operators cannot determine whether a phase angle difference exists in the first place. Generally, APS operators can monitor phase angles through SCADA, but in order to receive and review this data, the transmission line must be energized. After H-NG tripped, and prior to reenergizing the line, for example, APS had no way to know if the line could be reclosed within the permissive 60 degree setting of its synchro-check relay. It lacked situational awareness of the phase angle difference. Yet, APS informed WECC RC and CAISO that it believed the line could be reclosed quickly, when, in fact, this could not have been done due to the phase angle difference.[104]

To avoid a similar situation in the future, TOPs should ensure that they have adequate tools to determine phase angles after the loss of transmission lines. For example, they can install PMUs throughout their system, as APS plans to do, to increase their situational awareness of phase angles. Moreover, TOPs should ensure that their operators are trained to respond to phase angle differences by, for example, redispatching generation. In addition, TOPs should not underestimate the time required to reclose a line, particularly without first knowing the phase angle difference. Here, for example, APS likely could not have reclosed the line quickly, even had it known the phase angle difference, given system conditions on the day of the event.

Indeed, the inquiry conducted a series of power flow simulations and found that significant amounts of generation redispatch were needed to close the phase angle difference. ***Figure* 17**, on the next page, shows the relationship between the voltage phase angle of H-NG as generation is redispatched between California and Arizona. The dispatched approach adjusts the available generation nearest the Hassayampa and North Gila buses. As generation is dispatched to its maximum output in the vicinity of the two

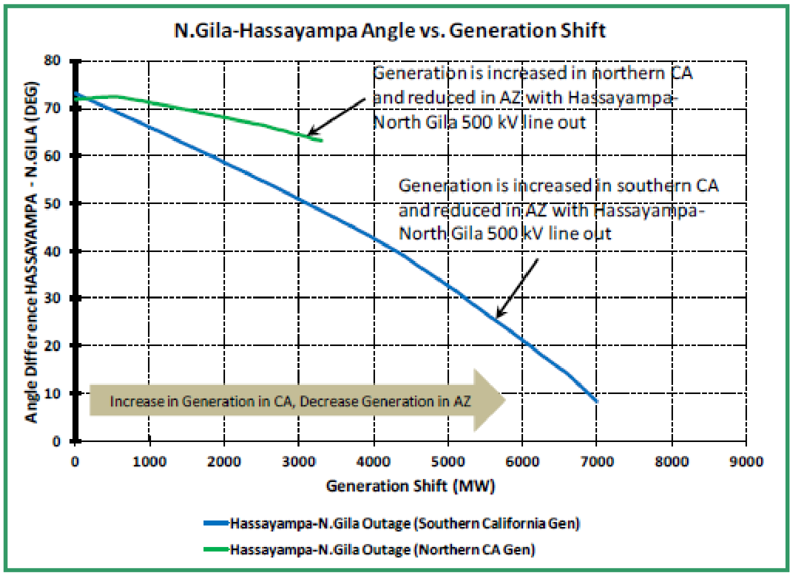
102 APS provides its certified operators with two training classes, Power System Dynamics and Dynamics of Disturbances, both of which address power angles and their ramifications. In addition, APS provides its new operator trainees with training on power angles.

103 APS plans to expand its use of PMUs to enable it to determine phase angle differences even without a line being energized. Through the PMU data, APS would be able to determine voltage and angle measurements on live buses in its substations, through which it could calculate phase angle differences.

104 APS did not intentionally mislead WECC RC and CAISO with this statement. Rather, it did not expect that there would have been such a large phase angle difference, as it had not previously experienced such a difference. Moreover, APS determined that the line was not damaged and, thus, it did not believe there would be any issues closing the line.

stations, other generators farther out are adjusted to effect the change in voltage phase angles.

Figure 17: Phase Angle of H-NG vs. Generation Shift



The blue line in Figure 17 illustrates that with the particular conditions of the September 8th event, approximately 1,800 MW needed to be redispatched on both ends of H-NG (and close to the terminals, in Southern California and Arizona) in order to close the voltage phase angle from 72 degrees to 60 degrees (i.e., to within the permissive 60 degree setting of the synchro-check relay). The green line shows that more generation—more than twice as much—must be redispatched if units are chosen in Northern California to close the angle between Hassayampa and North Gila.

While system operators could redispatch generation from available spinning reserves or commit units in the Southern and/or Northern California area, it is questionable how quickly 1,800 MW could be dispatched.

Appendix A: List of Acronyms Used in Report

ACE	Area Control Error
APS	Arizona Public Service
BA	Balancing Authority
BES	Bulk Electric System
BPS	Bulk-Power System
CAISO	California Independent System Operator, Inc.
CFE	Comisión Federal de Electricidad
CV	Coachella Valley
EMS	Energy Management System
GO	Generator Owner
GOP	Generator Operator
H-NG	APS's Hassayampa-North Gila 500 kV transmission line
IEEE	Institute of Electrical and Electronics Engineers
IID	Imperial Irrigation District
IROL	Interconnection Reliability Operating Limit
kV	Kilovolt
LAPS	Local Area Protection System
MVA	Megavolt-ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
OSS	California/Mexico Operations Study Subcommittee
OTC	Operating Transfer Capabilities
OTCPC	Operating Transfer Capability Policy Committee
PC	Planning Coordinator
PMU	Phasor Measurement Unit
RAS	Remedial Action Scheme
RC	Reliability Coordinator
RE	Regional Entity
RTCA	Real-Time Contingency Analysis
SASG	Southwest Area Study Group
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SE	State Estimator
SOE	Sequence of Events
SOL	System Operating Limit
SONGS	San Onofre Nuclear Generating Station
SPS	Special Protection System

SRP	Salt River Power
SWPL	Southwest Power Link
TO	Transmission Owner
TOP	Transmission Operator
TP	Transmission Planner
UFLS	Underfrequency Load Shedding
VAR	Volt-Ampere Reactive
WALC	Western Area Power Administration – Lower Colorado
WAPS	Wide Area Protection System
WECC	Western Electricity Coordinating Council
YCA	Yuma Cogeneration Associates

Appendix B: Table of Findings and Recommendations

The following table provides a complete list of findings and corresponding recommendations, each of which are discussed in detail at Section IV of the report.

NEXT-DAY PLANNING		
FINDING	**RECOMMENDATION**	**APPLICABLE ENTITIES**
Finding 1 – Failure to Conduct and Share Next-Day Studies: Not all of the affected TOPs conduct next-day studies or share them with their neighbors and WECC RC. As a result of failing to exchange studies, on September 8, 2011 TOPs were not alerted to contingencies on neighboring systems that could impact their internal system and the need to plan for such contingencies.	*Recommendation 1*: All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied.	TOPs
Finding 2 – Lack of Updated External Networks in Next-Day Study Models: When conducting next-day studies, some affected TOPs use models for external networks that are not updated to reflect next-day operating conditions external to their systems, such as generation schedules and transmission outages. As a result, these TOPs' next-day studies do not adequately predict the impact of external contingencies on their systems or internal contingencies on external systems.	*Recommendation 2*: TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.	TOPs, BAs, RCs
Finding 3 –Sub-100 kV Facilities Not Adequately Considered in Next-Day Studies: In conducting next-day studies, some affected TOPs focus primarily on the TOPs' internal SOLs and the need to stay within established Rated Path limits, without adequate consideration of some lower voltage facilities. As a result, these TOPs risk overlooking facilities that may become overloaded and impact the reliability of the BPS. Similarly,	*Recommendation 3*: TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.	TOPs, RCs

the RC does not study sub-100 kV facilities that impact BPS reliability unless it has specifically been alerted to issues with such facilities by individual TOPs or the RC has otherwise identified a particular sub-100 kV facility as affecting the BPS.		
Finding 4 – Flawed Process for Estimating Scheduled Interchanges: WECC RC's process for estimating scheduled interchanges is not adequate to ensure that such values are accurately reflected in its next-day studies. As a result, its next-day studies may not accurately predict actual power flows and contingency overloads.	*Recommendation 4*: WECC RC should improve its process for predicting interchanges in the day-ahead timeframe.	WECC RC
SEASONAL PLANNING		
FINDING	**RECOMMENDATION**	**APPLICABLE ENTITIES**
Finding 5 – Lack of Coordination in Seasonal Planning Process: The seasonal planning process in the WECC region lacks effective coordination. Specifically, the four WECC subregions do not adequately integrate and coordinate studies across the subregions, and no single entity is responsible for ensuring a thorough seasonal planning process. Instead of conducting a full contingency analysis based on all of the subregions' studies, the subregions rely on experience and engineering judgment in choosing which contingencies to discuss. As a result, individual TOPs may not identify contingencies in one subregion that may affect TOPs in the same or another subregion.	*Recommendation 5*: WECC RE should ensure better integration and coordination of the various subregions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between subregional studies. Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies.	WECC RE, TOPs
Finding 6 –External and Lower-Voltage Facilities Not Adequately Considered in Seasonal Planning Process: Seasonal planning studies do not adequately consider all facilities that may affect BPS reliability, including external facilities and lower-voltage facilities.	*Recommendation 6*: TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability.	TOPs
Finding 7 – Failure to Study Multiple Load Levels: TOPs do	*Recommendation 7*: TOPs should expand the cases on which they run their individual	TOPs

not always run their individual seasonal planning studies based on the multiple WECC base cases (heavy and light load summer, heavy and light load winter, and heavy spring), but, instead, may focus on only one load level. As a result, contingencies that occur during the shoulder seasons (or other load levels not studied) might be missed.	planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high load shoulder periods.	
Finding 8 – Not Sharing Overload Relay Trip Settings: In the seasonal planning process, at least one TOP did not share with neighboring TOPs overload relay trip settings on transformers and transmission lines that impacted external BPS systems.	*Recommendation 8*: TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater.	TOPs
NEAR- AND LONG-TERM PLANNING		
FINDING	**RECOMMENDATION**	**APPLICABLE ENTITIES**
Finding 9 – Gaps in Near- and Long-Term Planning Process: Gaps exist in WECC RE's, TPs' and PCs' processes for conducting near- and long-term planning studies, resulting in a lack of consideration for: (1) critical system conditions; (2) the impact of elements operated at less than 100 kV on BPS reliability; and (3) the interaction of protection systems. As a consequence, the affected entities did not identify during the planning process that the loss of a single 500 kV transmission line could potentially cause cascading outages. Planning studies conducted between 2006 and 2011 should have identified the critical conditions that existed on September 8th and proposed appropriate mitigation strategies.	*Recommendation 9*: WECC RE should take actions to mitigate these and any other identified gaps in the procedures for conducting near- and long-term planning studies. The September 8th event and other major events should be used to identify shortcomings when developing valid cases over the planning horizon and to identify flaws in the existing planning structure. WECC RE should then propose changes to improve the performance of planning studies on a subregional- and Interconnection-wide basis and ensure a coordinated review of TPs' and PCs' studies. TOPs, TPs and PCs should develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all protection systems, including RASs, Safety Nets (such as the SONGS separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of elements operated at less than 100 kV on BPS reliability.	WECC RE, TOPs, TPs, PCs
Finding 10 – Benchmarking WECC Dynamic Models: The inquiry obtained a very good correlation between the simulations and the actual event until the SONGS separation scheme activated. After	*Recommendation 10*: WECC dynamic models should be benchmarked by TPs against actual data from the September 8th event to improve their conformity to actual system performance. In particular, improvements to model performance from validation would be helpful in analysis of	TPs

activation of the scheme, however, neither the tripping of the SONGS units nor the system collapse of SDG&E and CFE could be detected using WECC dynamic models because some of the elements of the event are not explicitly included in those models. Sample simulations of the islanded region showed that by adding known details from the actual event, including UFLS programs and automatic capacitor switching, the simulation and event become more closely aligned following activation of the SONGS separation scheme.	under and/or over frequency events in the Western Interconnection and the stability of islanding scenarios in the SDG&E and CFE areas.	
SITUATIONAL AWARENESS		
FINDING	**RECOMMENDATION**	**APPLICABLE ENTITIES**
Finding 11 – Lack of Real-Time External Visibility: Affected TOPs have limited real-time visibility outside their systems, typically monitoring only one external bus. As a result, they lack adequate situational awareness of external contingencies that could impact their systems. They also may not fully understand how internal contingencies could affect SOLs in their neighbors' systems.	*Recommendation 11*: TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	TOPs
Finding 12 – Inadequate Real-Time Tools: Affected TOPs' real-time tools are not adequate or, in one case, operational to provide the situational awareness necessary to identify contingencies and reliably operate their systems.	*Recommendation 12*: TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	TOPs
Finding 13 – Reliance on Post-Contingency Mitigation Plans: One affected TOP operated in an unsecured N-1 state on September 8, 2011, when it relied on post-contingency mitigation plans for its internal contingencies and subsequent overload and tripping, while assuming there would be	*Recommendation 13*: TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency. As part of this review, TOPs should consider the effect of relays that automatically isolate	TOPs

sufficient time to mitigate the contingencies. Post-contingency mitigation plans are not viable under all circumstances, such as when equipment trips on overload relay protection that prevents operators from taking timely control actions. If this TOP had used pre-contingency measures on September 8th, such as dispatching additional generation, to mitigate first contingency emergency overloads for its internal contingencies, the cascading outages that were triggered by the loss of H-NG might have been avoided with the prevailing system conditions on September 8, 2011.	facilities without providing operators sufficient time to take mitigating measures.	
Finding 14 – WECC RC Staffing Concerns: WECC RC staffs a total of four operators at any one time to meet the functional requirements of an RC, including continuous monitoring, conducting studies, and giving directives. The September 8th event raises concerns that WECC RC's staffing is not adequate to respond to emergency conditions.	*Recommendation 14*: WECC RC should evaluate the effectiveness of its staffing level, training and tools. Based on the results of this evaluation, it should determine what actions are necessary to perform its functions appropriately as the RC and address any identified deficiencies.	WECC RC
Finding 15 – Failure to Notify WECC RC and Neighboring TOPs Upon Losing RTCA: On September 8, 2011, at least one affected TOP lost the ability to conduct RTCA more than 30 minutes prior to and throughout the course of the event due to the failure of its State Estimator to converge. The entity did not notify WECC RC or any of its neighboring TOPs, preventing this entity from regaining situational awareness.	*Recommendation 15*: TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities.	TOPs
Finding 16 – Discrepancies Between RTCA and Planning Models: WECC's model used by TOPs to conduct RTCA studies is not consistent with WECC's planning model and produces conflicting solutions.	*Recommendation 16*: WECC should ensure consistencies in model parameters between its planning model and its RTCA model and should review all model parameters on a consistent basis to make sure discrepancies do not occur.	WECC
CONSIDERATION OF BES EQUIPMENT		

FINDING	RECOMMENDATION	APPLICABLE ENTITIES
Finding 17 – Impact of Sub-100 kV Facilities on BPS Reliability: WECC RC and affected TOPs and BAs do not consistently recognize the adverse impact sub-100 kV facilities can have on BPS reliability. As a result, sub-100 kV facilities might not be designated as part of the BES, which can leave entities unable to address the reliability impact they can have in the planning and operations time horizons. If, prior to September 8, 2011, certain sub-100 kV facilities had been designated as part of the BES and, as a result, were incorporated into the TOPs' and RC's planning and operations studies, or otherwise had been incorporated into these studies, cascading outages may have been avoided on the day of the event.	*Recommendation 17*: WECC, as the RE should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems.	WECC RE, TOPs, BAs
IROL DERIVATIONS		
FINDING	**RECOMMENDATION**	**APPLICABLE ENTITIES**
Finding 18 – Failure to Establish Valid SOLs and Identify IROLs: The cascading nature of the event that led to uncontrolled separation of San Diego, IID, Yuma, and CFE indicates that an IROL was violated on September 8, 2011, even though WECC RC did not recognize any IROLs in existence on that day. In addition, the established SOL of 2,200 MW on Path 44 and 1,800 MW on H-NG are invalid for the present infrastructure, as demonstrated by the event.	*Recommendation 18.1*: WECC RC should recognize that IROLs do exist on its system and, thus, should study IROLs in the day-ahead timeframe and monitor potential IROL exceedances in real-time. *Recommendation 18.2*: WECC RC should work with TOPs to consider whether any SOLs in the Western Interconnection constitute IROLs. As part of this effort, WECC RC should: (1) work with affected TOPs to consider whether Path 44 and H-NG should be recognized as IROLs; and (2) validate existing SOLs, and ensure that they take into account all transmission and generation facilities and protection systems that impact BPS reliability.	WECC RC, TOPs
PROTECTION SYSTEMS		
FINDING	**RECOMMENDATION**	**APPLICABLE ENTITIES**
Finding 19 – Lack of Coordination of the S Line RAS: Several TOs and TOPs did not properly coordinate a RAS by: (1)	*Recommendation 19*: The TOs and TOPs responsible for design and coordination of the S Line RAS should revisit its design basis and protection settings to ensure	TOs, TOPs

not performing coordination studies with the overload protection schemes on the facilities that the S Line RAS is designed to protect; and (2) not assessing the impact of setting relays to trip generation sources and a 230 kV transmission tie line prior to the operation of a single 161/92 kV transformer's overload protection. As a result, BES facilities were isolated in excess of those needed to maintain reliability, with adverse impact on BPS reliability.	coordination with other protection systems in order to prevent adverse impact to the BPS, premature operation, and excessive isolation of facilities. TOs and TOPs should share any changes to the S Line RAS with TPs and PCs so that they can accurately reflect the S Line RAS when planning.	
Finding 20 – Lack of Coordination of the SONGS Separation Scheme: SCE did not coordinate the SONGS separation scheme with other protection systems, including protection and turbine control systems on the two SONGS generators. As a result, SCE did not realize that Units 2 and 3 at SONGS would trip after operation of the separation scheme.	*Recommendation 20*: SCE should ensure that the SONGS separation scheme is coordinated with other protection schemes, such as the generation protection and turbine control systems on the units at SONGS and UFLS schemes.	SCE
Finding 21 – Effect of SONGS Separation Scheme on SONGS Units: The SONGS units tripped due to their turbine control systems detecting unacceptable acceleration following operation of the SONGS separation scheme.	*Recommendation 21*: GOs and GOPs should evaluate the sensitivity of the acceleration control functions in turbine control systems to verify that transient perturbations or fault conditions in the transmission system resulting in unit acceleration will not result in unit trip without allowing time for protective devices to clear the fault on the transmission system.	GOs, GOPs
Finding 22 – Lack of Review and Studying Impact of SPSs: Although WECC equates SPSs with RASs, prior to October 1, 2011, WECC's definition of RAS excluded many protection systems that would be included within NERC's definition of SPS. As a result, WECC did not review and assess all NERC-defined SPSs in its region, and WECC's TOPs did not perform the required review and assessment of all NERC-defined SPSs in their areas.	*Recommendation 22*: WECC RE, along with TOs, GOs, and Distribution Providers (DPs), should periodically review the purpose and impact of RASs, including Safety Nets and Local Area Protection Schemes, to ensure they are properly classified, are still necessary, serve their intended purposes, are coordinated properly with other protection systems, and do not have unintended consequences on reliability. WECC RE and the appropriate TOPs should promptly conduct these reviews for the SONGS separation scheme and the S Line RAS.	WECC RE, TOs, GOs, DPs, TOPs

Finding 23 – Effect of Inadvertent Operation of SONGS Separation Scheme on BPS Reliability: The inquiry's simulation of the event shows that the inadvertent operation of the SONGS separation scheme under normal system operations could lead to a voltage collapse and blackout in the SDG&E areas under certain high load conditions.	*Recommendation 23*: CAISO and SCE should promptly verify that the inadvertent operation of the SONGS separation scheme does not pose an unacceptable risk to BPS reliability. Until this verification can be completed, they should consider all actions to minimize this risk, up to and including, temporarily removing the SONGS separation scheme from service.	CAISO, SCE
Finding 24 – Not Recognizing Relay Settings When Establishing SOLs: An affected TO did not properly establish the SOL for two transformers, as the SOL did not recognize that the most limiting elements (protective relays) were set to trip below the established emergency rating. As a result, the transformers tripped prior to the facilities being loaded to their emergency ratings during the restoration process, which delayed the restoration of power to the Yuma load pocket.	*Recommendation 24*: TOs should reevaluate their facility ratings methodologies and implementation of the methodologies to ensure that their ratings are equal to the most limiting piece of equipment, including relay settings. No relay settings should be set below a facility's emergency rating. When the relay setting is determined to be the most limiting piece of equipment, consideration should be given to reviewing the setting to ensure that it does not unnecessarily restrict the transmission loadability.	TOs
Finding 25 – Margin Between Overload Relay Protection Settings and Emergency Rating: Some affected TOs set overload relay protection settings on transformers just above the transformers' emergency rating, resulting in facilities being automatically removed from service before TOPs have sufficient time to take control actions to mitigate the resulting overloads. One TO in particular set its transformers' overload protection schemes with such narrow margins between the emergency ratings and the relay trip settings that the protective relays tripped the transformers following an N-1 contingency.	*Recommendation 25*: TOs should review their transformers' overload protection relay settings with their TOPs to ensure appropriate margins between relay settings and emergency ratings developed by TOPs. For example, TOs could consider using the settings of Reliability Standard PRC-023-1 R.1.11 even for those transformers not classified as BES. PRC-023-1 R.1.11 requires relays to be set to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater.	TOs, TOPs
Finding 26 –Relay Settings and Proximity to Emergency Ratings: Some TOs set relays to isolate facilities for loading conditions slightly above their thirty minute emergency ratings. As a result, several transmission lines and transformers tripped	*Recommendation 26*: TOs should evaluate load responsive relays on transmission lines and transformers to determine if the settings can be raised to provide more time for TOPs to take manual action to mitigate overloads that are within the short-time thermal capability of the equipment instead of allowing relays to prematurely isolate the	TOs, TOPs

within seconds of exceeding their emergency ratings, leaving TOPs insufficient time to mitigate overloads.	transmission lines. If the settings cannot be raised to allow more time for TOPs to take manual action, TOPs must ensure that the settings are taken into account in developing facility ratings and that automatic isolation does not result in cascading outages.	

ANGULAR SEPARATION		
FINDING	**RECOMMENDATION**	**APPLICABLE ENTITIES**
Finding 27 – Phase Angle Difference Following Loss of Transmission Line: A TOP did not have tools in place to determine the phase angle difference between the two terminals of its 500 kV line after the line tripped. Yet, it informed the RC and another TOP that the line would be restored quickly, when, in fact, this could not have been accomplished.	*Recommendation 27*: TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences. TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day contingency analyses that address the angular differences across opened system elements.	TOPs

Appendix C: Comparison of August 2003 and September 2011 Blackouts

On August 14, 2003, an estimated 50 million people throughout the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. A day later, the joint U.S.-Canada Power System Outage Task Force began investigating the causes of the blackout and considering ways to prevent such outages in the future. The task force detailed its findings and recommendations in an April 2004 report.[105] A comparison of the findings and recommendations in this April 2004 report and the instant report on the September 8, 2011, blackout reveals commonalities between the two events.

Although the August 2003 and September 2011 blackouts were triggered by different initiating events—tree touches in 2003 compared to a switching error in 2011—both blackouts had common underlying causes. First, affected entities in both events did not conduct adequate long-term and operations planning studies necessary to understand vulnerabilities on their systems. Second, affected entities in both events had inadequate situational awareness leading up to and during the disturbances. In addition to these two underlying causes, both events were exacerbated by protection system relays that tripped facilities without allowing operators sufficient time to take mitigating measures. These similarities are highlighted below, with excerpts from both reports to illustrate specific comparisons.

Inadequate Long-Term and Operations Planning

The 2003 Blackout Report states that "FirstEnergy was not [operating its system securely] because the company had not conducted the long-term and operational planning studies needed to understand [certain] vulnerabilities and their operational implications."[106] Similarly, this inquiry's report found that several entities' operational and long-term studies did not adequately ensure the reliable operation of their systems. Specifically, both reports described relevant planning studies that: (1) did not adequately identify and study critical external facilities; (2) did not adequately analyze potential contingency scenarios; and (3) were based on inaccurate models and invalid system operating limits (SOLs).

105 Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (U.S.-Canada Power System Outage Task Force: April 2004) (2003 Blackout Report).

106 2003 Blackout Report at 23.

Inadequate Long Term and Operations Planning

Issue	2003 Blackout	2011 Blackout
Insufficient Analysis in Seasonal Studies	"[T]he studies FirstEnergy relied on . . . were not robust, thorough, or up-to-date. This left FE's planners and operators with a deficient understanding of their system's capabilities and risks under a range of system conditions." (P. 39). "FE's 2003 Summer Study focused primarily on single-contingency (N-1) events, and did not consider significant multiple contingency losses and security. . . . Overall, the summer study posited less stressful system conditions than actually occurred August 14, 2003 (when load was well below historic peak demand)." (P 39).	"TOPs do not always run their individual seasonal planning studies based on the multiple WECC base cases (heavy and light load summer, heavy and light load winter, and heavy spring), but, instead, may focus on only one load level." (Finding 7) "Seasonal planning studies do not adequately consider all facilities that may affect BPS reliability, including external facilities and lower-voltage facilities."(Finding 6) "In the seasonal planning process, at least one TOP did not share with neighboring TOPs overload relay trip settings on transformers and transmission lines that impacted external BPS systems." (Finding 8)
Inadequate Identification and Study of Critical External Facilities	"On August 14 four or five capacitor banks within the Cleveland-Akron area had been removed from service for routine inspection. . . . These static reactive power sources are important for voltage support. . . . The unavailability of the critical reactive resources was not known to those outside of FirstEnergy." (PP. 26-27). "NERC policy requires that critical facilities be identified and that neighboring control areas and reliability coordinators be made aware of the status of those facilities to identify the impact of those conditions on their own facilities. However, FE never identified these capacitor banks as critical and so did not pass on status information to others." (P. 27).	"Not all of the affected TOPs conduct next-day studies or share them with their neighbors and WECC RC. . . .TOPs were not alerted to contingencies on neighboring systems that could impact their internal system and the need to plan for such contingencies." (Finding 1) "In conducting next-day studies, some affected TOPs focus primarily on the TOPs' internal SOLs and the need to stay within established Rated Path limits, without adequate consideration of some lower voltage facilities." (Finding 3) "[In conducting next-day studies,] . . . the RC does not study sub-100 kV facilities that impact BPS reliability unless it has specifically been alerted to issues with such facilities by individual TOPs..." (Finding 3)

Inaccurate Dynamic Models	"The after-the-fact models developed to simulate August 14 conditions and events found that the dynamic modeling assumptions for generator and load power factors in regional planning and operating models were frequently inaccurate." (P. 160).	". . . neither the tripping of the SONGS units nor the system collapse of SDG&E and CFE could be detected using WECC dynamic models because some of the elements of the event are not explicitly included in those models." (Finding 10)

To mitigate these concerns, the 2003 Blackout Report recommended that "NERC should work with the regional reliability councils to establish regional power system models that enable the sharing of consistent and validated data among entities in the region,"[107] and "[c]larify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages."[108] This inquiry's report likewise recommends that entities cooperate and coordinate more effectively across all planning horizons, especially by increasing visibility in both external systems and lower voltage facilities that could impact BPS reliability.

Inadequate Situational Awareness

The 2003 Blackout Report stated, "A principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools and backup capabilities."[109] Similarly, the instant inquiry determined that inadequate real-time situational awareness contributed to the cascading outages. In both events, for example, the affected entities' real-time monitoring tools were not adequate to alert operators to system conditions and contingencies. Also, some of the affected entities in both events did not use their real-time tools to monitor system conditions. As a result of these situational awareness issues, affected entities in both events were not aware that they were no longer operating in a secure N-1 state and were not alerted to the need to take corrective actions.

Inadequate Situational Awareness		
Issue	2003 Blackout	2011 Blackout
System Visibility	"MISO [the Reliability Coordinator] had interpretive and operational tools and a large amount of system data, but had a limited view of FE's system." (P. 67).	"Affected TOPs have limited real-time visibility outside their systems, typically monitoring only one external bus. As a result, they lack adequate situational awareness of external contingencies that could impact

[107] 2003 Blackout Report at 160.

[108] 2003 Blackout Report at 3.

[109] 2003 Blackout Report at 159.

Inadequate Situational Awareness		
Issue	2003 Blackout	2011 Blackout
		their systems. They also may not fully understand how internal contingencies could affect SOLs in their neighbors' systems." (Finding 11)
Inadequate Real-Time Monitoring Tools	"FE's operational monitoring equipment was not adequate to alert FE's operators regarding important deviations in operating conditions and the need for corrective action." (P. 19). "FE's control room operators lost the alarm function that provided audible and visual indications when a significant piece of equipment changed from an acceptable to a problematic condition." (P. 51). MISO's incomplete tool set and the failure to supply its state estimator with correct system data on August 14 contributed to the lack of situational awareness." (P. 159).	"Affected TOPs' real-time tools are not adequate or, in one case, operational to provide the situational awareness necessary to identify contingencies and reliably operate their systems." (Finding 12) ". . . a TOP lost the ability to conduct [Real Time Contingency Analysis] RTCA more than 30 minutes prior to and throughout the course of the event ...[and] did not notify WECC RC or any of its neighboring TOPs..."(Finding 15)
Operating in an Unsecure State	"FE's operators were not aware that the system was operating outside first contingency limits . . . because they did not conduct a contingency analysis." (P. 64). "MISO's reliability coordinators were using non-real-time data to support real-time "flowgate" monitoring. This prevented MISO from detecting an N-1 security violation in FE's system and from assisting FE in necessary relief actions." (P. 19). "Since FE's operators were not aware and did not recognize events as they were occurring, they took no actions to return the system to a reliable state." (P. 65).	"The cascading nature of the event that led to uncontrolled separation of San Diego, IID, Yuma, and CFE indicates that an [interconnection reliability operating limit] IROL was violated . . . In addition, the established SOLs of 2,200 MW on Path 44 and 1,800 MW on H-NG are invalid..."(Finding 18) "One affected TOP operated in an unsecured N-1 state. . . . when it relied on post-contingency mitigation plans for its internal contingencies and subsequent overloads and trips, while assuming there would be sufficient time to mitigate the contingencies." (Finding 13)

To remedy these weaknesses in situational awareness, the 2003 Blackout Report recommended that entities [e]valuate and adopt better real-time tools for operators and reliability coordinators."[110] Similarly, this inquiry's report recommends that operators develop and effectively utilize the real-time tools at their disposal and include all facilities that can impact BPS reliability.

Protection Systems

During both events, protection system settings exacerbated and accelerated the cascading nature of the outages. As stated in the 2003 Blackout Report, zone 3 relay settings "did not cause the blackout, [but] it is certain that they greatly expanded and accelerated the spread of the cascade."[111] Similarly, load responsive relay settings accelerated the September 8th cascade and effectively eliminated the window in which operators could have taken mitigating actions.

Protection Systems		
Issue	**2003 Blackout**	**2011 Blackout**
Overly Conservative Relay Protection Settings	"A few lines have zone 3 settings designed with overload margins close to the long-term emergency limit of the line. . . .Thus, it is possible for a zone 3 relay to operate on line load or overload in extreme contingency conditions even in the absence of a fault." (P. 80)	"Some affected TOs set overload relay protection settings on transformers just above the transformers' emergency rating, resulting in facilities being automatically removed from service before TOPs have sufficient time to take control actions . . . following an N-1 contingency." (Finding 25)
Cascading Relay Overload Trips	"[B]ecause these zone 2 and 3 relays tripped after each line overloaded, these relays were the common mode of failure that accelerated the geographic spread of the cascade." (P. 80)	"Some TOs set relays to isolate facilities for loading conditions slightly above their thirty minute emergency ratings. As a result, several transmission lines and transformers tripped within seconds of exceeding their emergency ratings, leaving TOPs insufficient time to mitigate overloads." (Finding 26)
Relay Protection Acting Too Quickly to Allow System Operators to Take Action	"[T]he speed of the zone 2 and 3 operations across Ohio and Michigan eliminated any possibility . . . that either operator action or automatic intervention could have limited or mitigated the growing cascade." (P. 80).	"Some affected TOs set overload relay protection settings on transformers just above the transformers' emergency rating, resulting in facilities being automatically removed from service before TOPs have

[110] 2003 Blackout Report at 159.

[111] 2003 Blackout Report at 82. Zone 3 relays "provide breaker failure and relay backup for remote distance faults on a transmission line." *Id.* at 80.

Protection Systems		
Issue	**2003 Blackout**	**2011 Blackout**
		sufficient time to take control actions...” (Finding 25) “. . . several transmission lines and transformers tripped within seconds of exceeding their emergency ratings, leaving TOPs insufficient time to mitigate overloads. (Finding 26)

After seeing the consequences of conservative zone 3 settings, the 2003 Blackout Report recommended that “[i]ndustry is to review zone 3 relays on lines of 230 kV and higher.”[112] This inquiry’s report similarly recommends that Transmission Owners review their facilities’ overload relay protection settings to ensure the appropriate margin between relay settings and emergency ratings.

[112] 2003 Blackout Report at 158.

Appendix D: Benchmarking the Model

I. Introduction and Background

The inquiry's Modeling and Simulation Team replicated system conditions on September 8, 2011, and the events leading up to the blackout. The model reflects the state of the electric system before and during the event, with the real power output of generators dispatched to the values recorded in SCADA data. With any major event on the BPS, it is important to accurately model the system before and during the event in order to: (1) verify the Sequence of Events; (2) support reconciliation of disparate measurement data; and (3) simulate and evaluate hypothetical scenarios, or "what-if" scenarios.

In order to ensure the accuracy of these tasks, the Modeling and Simulation Team benchmarked the model to recorded SCADA and PMU measurements using the following guidelines. Key facilities and interfaces in the affected area were generally benchmarked to within 5% or 10 MVA accuracy to the measured data. Generator reactive outputs were also checked against recorded values to ensure that the representation of reactive power margin was reasonably accurate. The team also monitored most other facilities in the affected area to ensure that the flows and voltage were reasonably close to measured data. Many of these other facilities also met the same guidelines used to benchmark the key facilities and interfaces.

The iterative process between benchmarking and case alteration has traditionally been time-consuming. The team pursued methods that would ultimately decrease the amount of time spent benchmarking so that results could quickly be used to identify problem areas in the case and make appropriate adjustments. Because the team received SCADA and PMU measurement data from many sources and entities, the data was: (1) organized into a consistent format, useful for automated benchmarking; and (2) cross-checked and verified for accuracy. In organizing the data, the team also considered how each data point would map back to both power flow and dynamics results. The team ultimately achieved a single process to: (1) import power flow results; (2) import dynamics results; (3) compare the results to measured data from many sources at various quasi-steady state times during the event; (4) export tables showing the percentage accuracy; and (5) export graphs showing the accuracy of the results relative to measured data throughout the event.

II. Discussion

The locations and measurements that the team selected for benchmarking were naturally predicated on the available measurements. While the team compared each available data point to the model results, it did not benchmark the model to all available data points. Instead the team focused its benchmarking effort on a "study area" that included SDG&E, IID, the APS Yuma load pocket, and portions of CFE and SCE. The team gave preference to measurements that were available in multiple data sources with some reasonable agreement between the different sources, and particular preference to those locations where PMU measurements were available, because these measurements could also be benchmarked against a full dynamics simulation.

Following each set of simulations, the team reviewed the benchmarking data both graphically and tabularly, and tuned the modeling case and simulation parameters in an attempt to bring the case closer to measured reality. The team would then re-run the simulation, and repeat this process.

Custom Interfaces

Even though the team selected the best possible set of benchmarking data, and a substantial amount of work went into calibrating the study area of the modeling case to those measurements, inconsistencies between some data points persisted. These inconsistencies arose due to the multitude of subtle settings and parameters for equipment, such as a changed tap on a single transformer affecting reactive power flow. For this reason, the team developed "custom interfaces" to benchmark an aggregation of points. If an aggregated, modeled sub-system was very close to the actual measurements for that system, then the simulation could be trusted to accurately reflect the system. For example, if reactive power flow was misallocated to a pair of adjacent transformers sourcing a sub-system, the specific reactive flow on each transformer may not be of particular importance to the model. However, the reactive flow to the aggregate load being served by those transformers may have a significant impact on a neighboring sub-system, and be crucial to effective benchmarking.

The custom interfaces were also defined so as to indicate the amount of flow into or across a particular sub-system. For example, the calculated flows at the "IID North 92 kV System" interface give an idea of the amount and nature of the load in the northern IID 92 kV system. The custom interfaces selected include:

- **IID North 92 kV System:** All transmission sources for the northern IID 92 kV system, including the 230/92 kV transformers at Coachella Valley and Ramon, the 161/92 kV transformers at Coachella Valley and Avenue 58, and the 92 kV lines between the northern and southern IID systems.

- **IID South 92 kV System:** All transmission sources for the southern IID 92 kV system, including the 230 kV transformer at El Centro, the 161/92 kV transformers at El Centro and Niland, and the 92 kV lines between the southern and northern IID systems.
- **Yuma Pocket:** Interfaces between the Yuma area 69 kV system (including portions of both APS and WALC service territories) and higher-voltage systems, including the 500/69 kV transformers at N. Gila, the 161/69 kV transformers at Gila, and the 161 kV line from Pilot Knob to Yucca.
- **Southwest California Desert Imports:** All transmission sources into the IID/SDG&E/CFE/Yuma area other than Path 44.

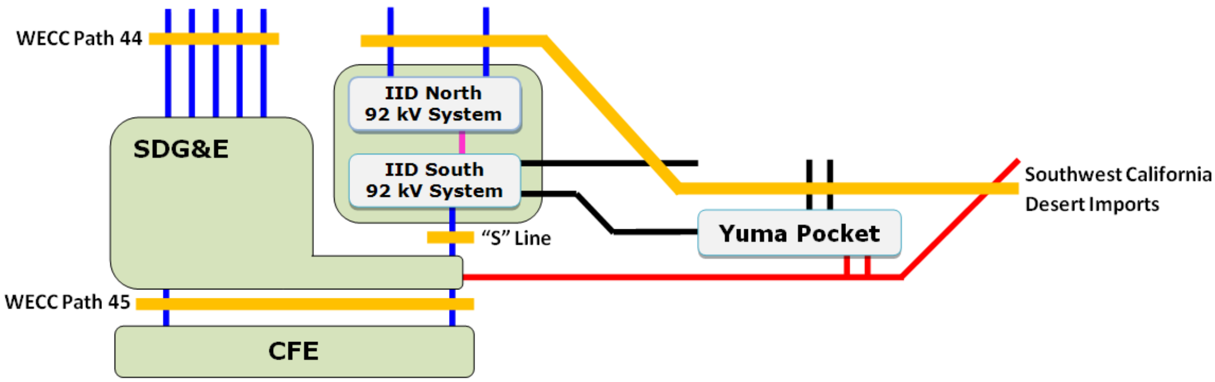


Figure 1: Key Facilities and Interfaces

Key Facilities and Interfaces

The team chose key facilities and interfaces in the affected area as a way to quickly evaluate the model before fine-tuning it on a more granular level. These key facilities and interfaces were benchmarked to within 5% or 10 MVA accuracy to the measured data throughout the entire event. The key facilities and interfaces are listed below.

- WECC Path 44
- Southwest California Desert Imports
- IID Northern 92 kV System
- Niland-Blythe 161 kV Transmission Line
- IID Southern 92 kV System
- Imperial Valley-El Centro 230 kV Transmission Line ("S" Line)
- Miguel-Imperial Valley 500 kV Transmission Line
- Yuma Pocket
- El Centro-Pilot Knob 161 kV Transmission Line
- Pilot Knob-Knob 161 kV Transmission Line
- Pilot Knob-Yucca 161 kV Transmission Line
- Julian Hinds-Mirage 230 kV Transmission Line
- Julian Hinds-Eagle Mountain 230 kV Transmission Line

III. Results

The following graphs demonstrate the benchmarking results. Each plot gives both power flow (see "TSS" in graph legend)[113] and dynamic simulation (see "DYD" in graph legend)[114] results at each selected time step, with the corresponding SCADA and/or PMU measurement, as available. In some instances, known issues with measured data are annotated on the charts, such as SCADA measurement errors for Coachella Valley during the interval following the initiating event.

The simulated MW values follow the measurements more closely than the simulated MVAR values. This is due to complexity involved in tuning voltage at each bus due to incomplete data, such as unknown tap values on large transformers. Overall, the MVA values are within our benchmarking guidelines.

The team also provided a table that compares: (1) the base case at 15:27:00 to the measured data; and (2) the case just prior to the loss of the Coachella Valley transformers at 15:28:11 to the measured data. This table does not compare the dynamics values to the base case at 15:27:00 because the power flow base case was the foundation for the dynamics simulation, meaning the values would be equal.

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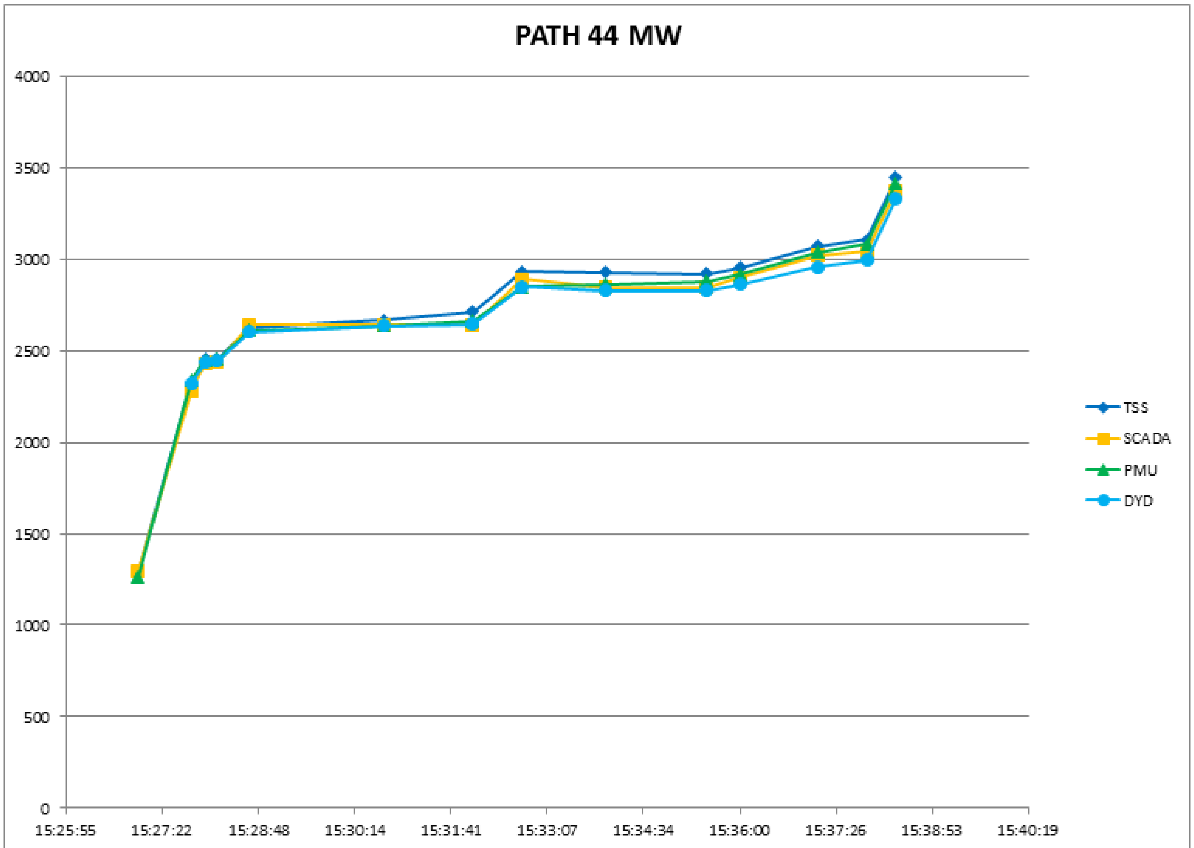
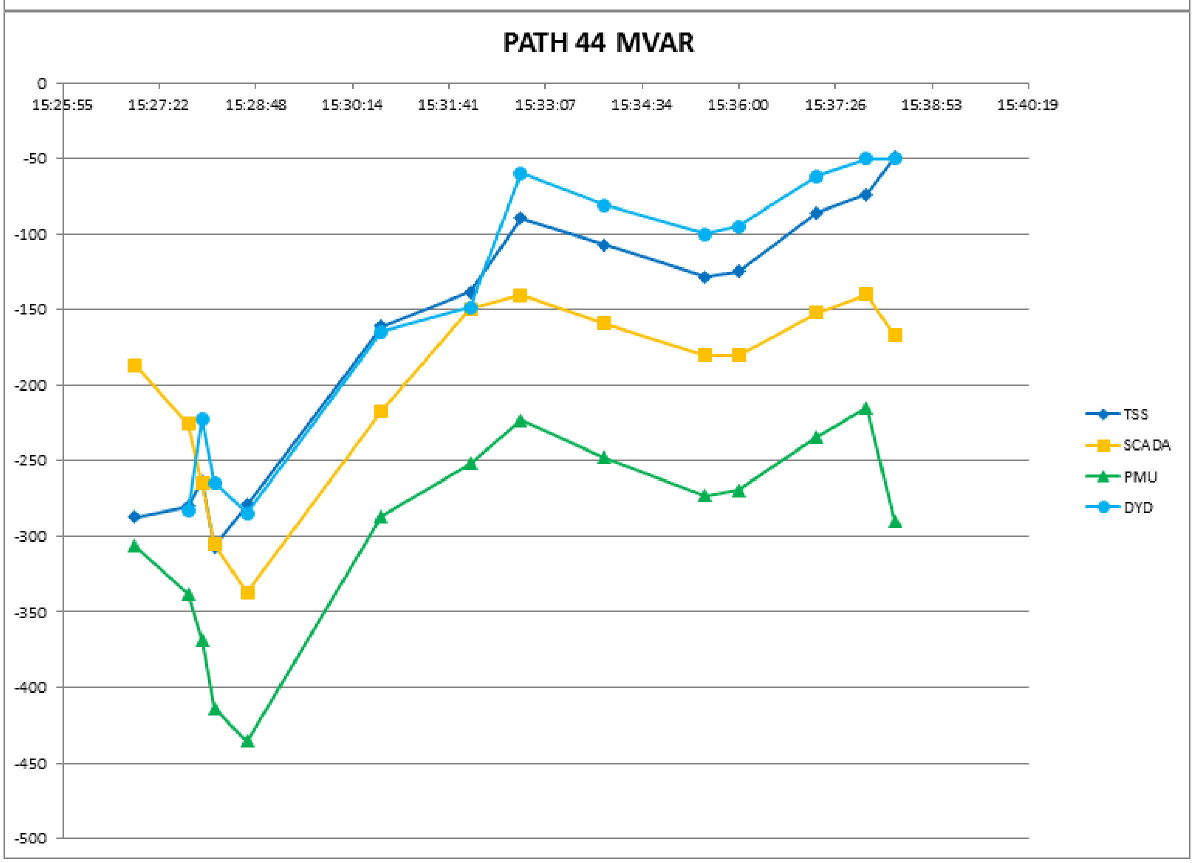
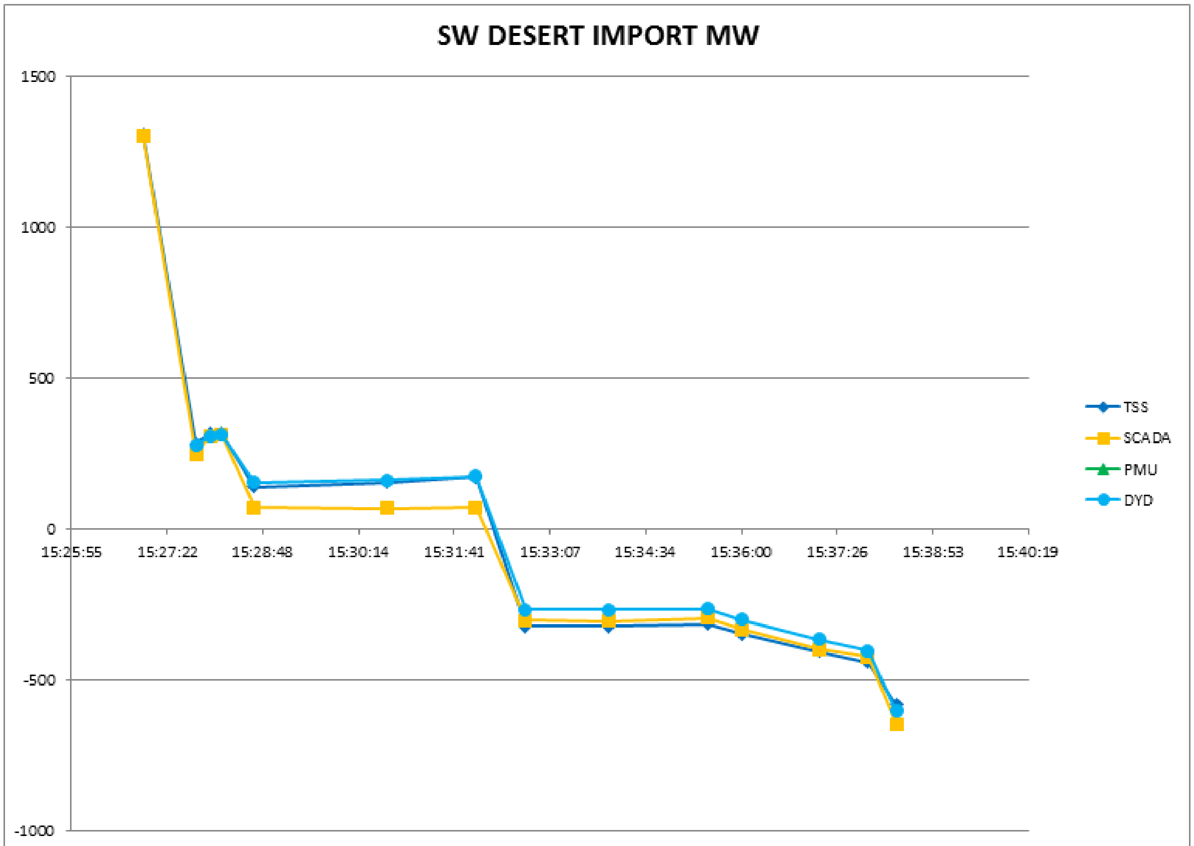
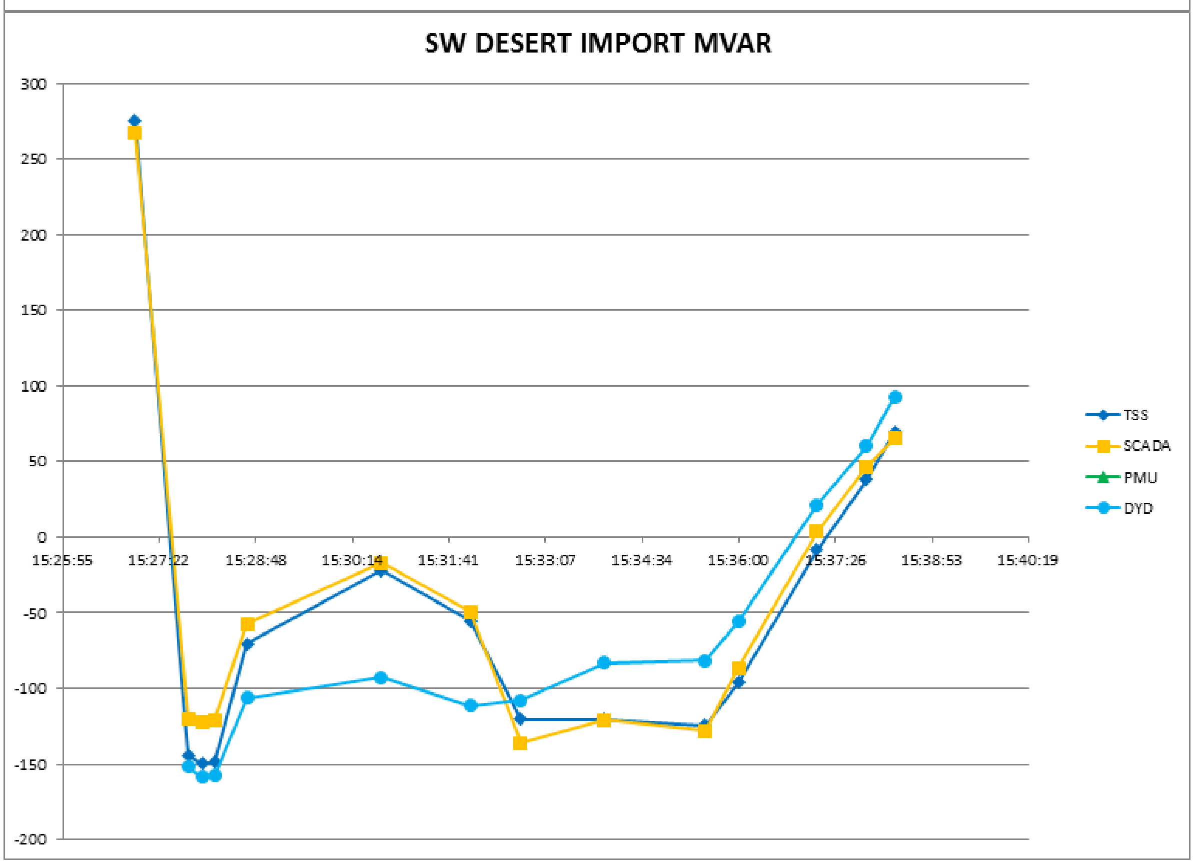
113 Time Sequence Simulation.

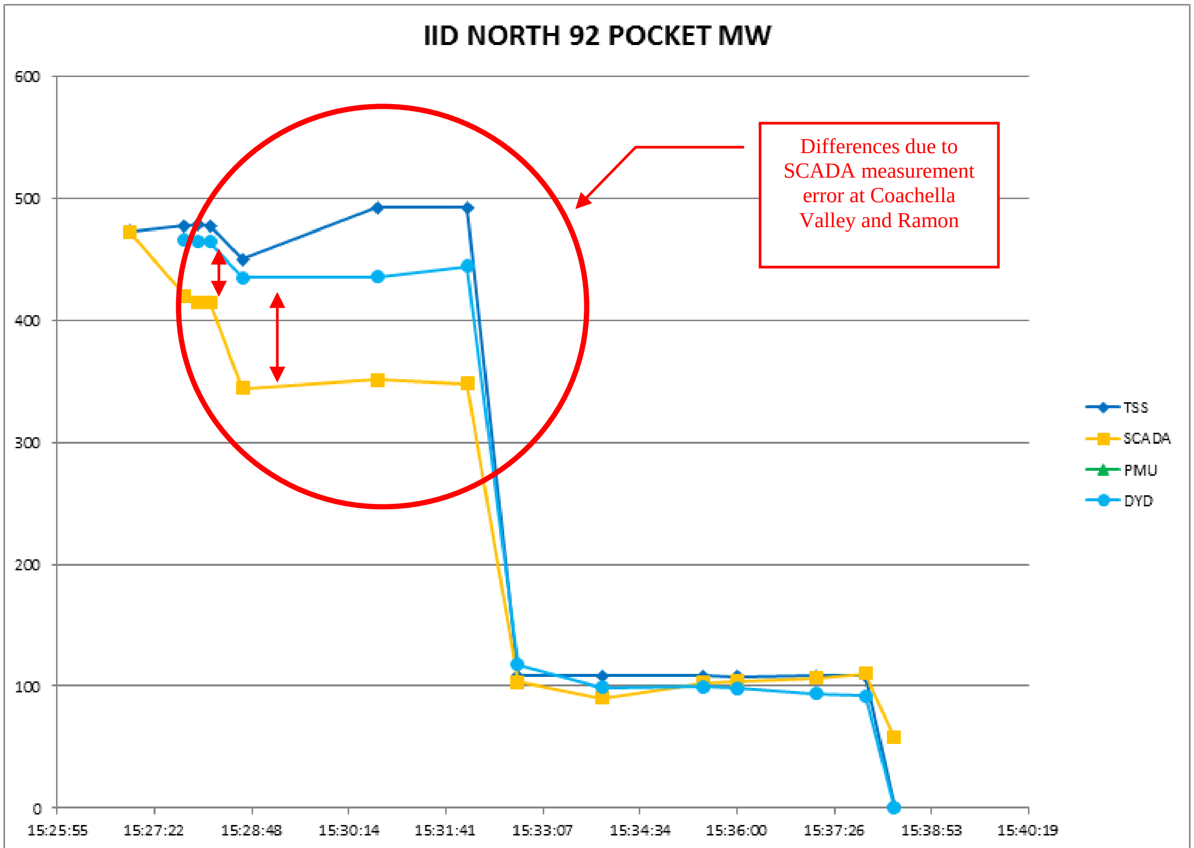
114 Dynamics Data.

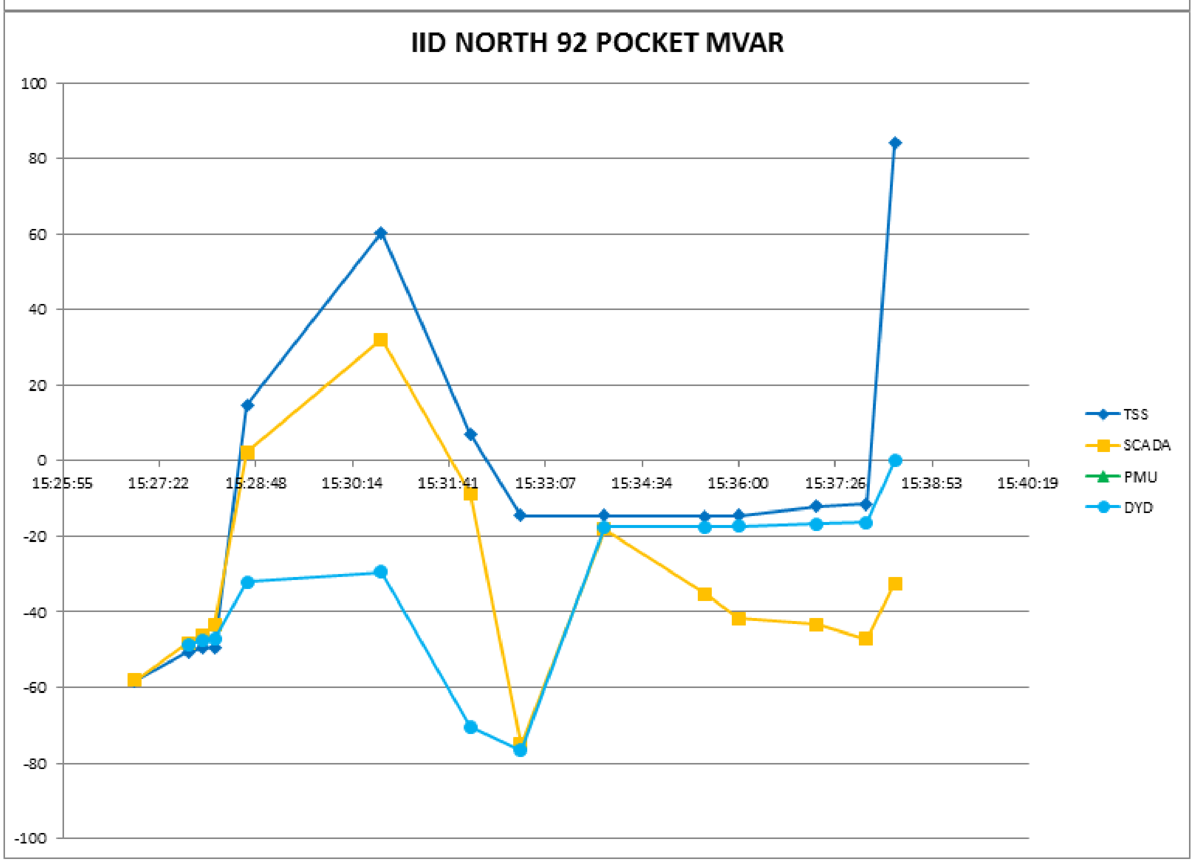

PATH 44 MW
4000
3500
3000
2500
2000
1500
1000
500
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

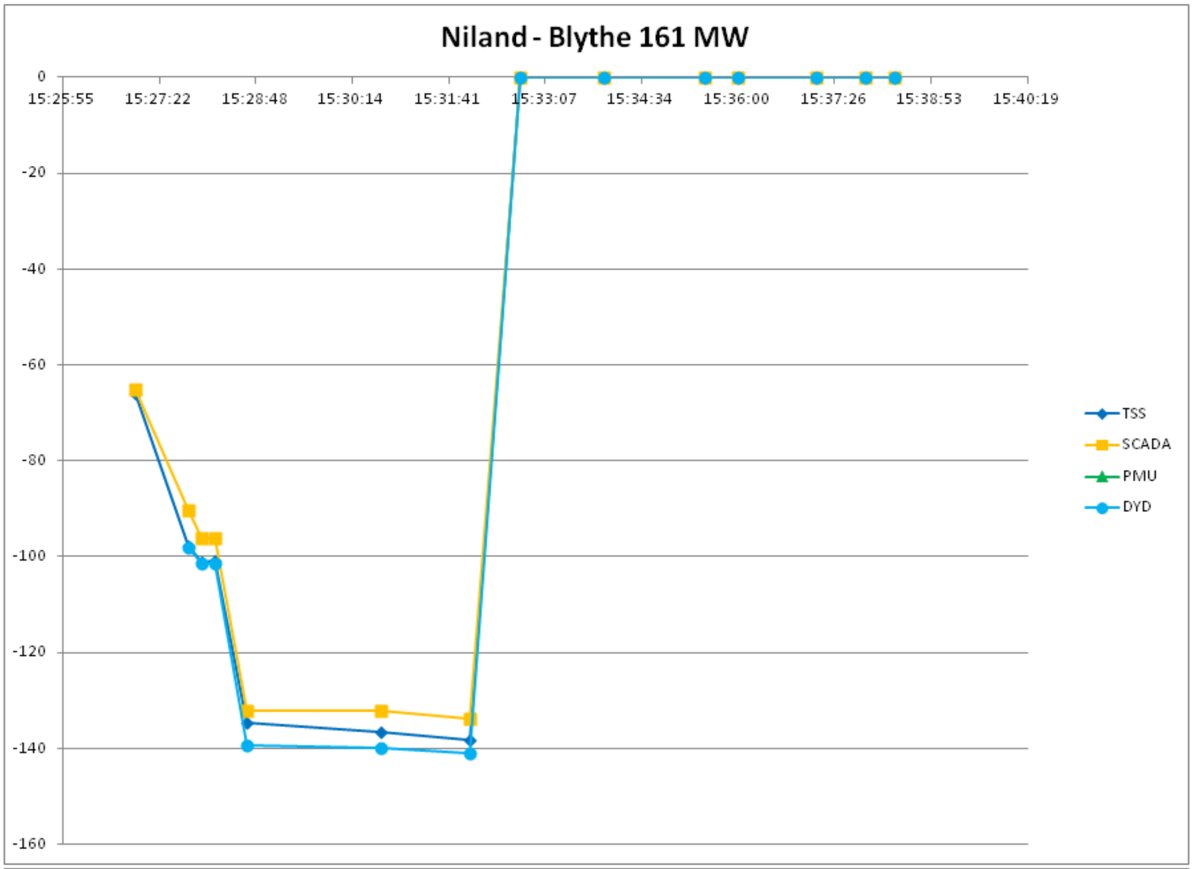

PATH 44 MVAR
0
-50
-100
-150
-200
-250
-300
-350
-400
-450
-500
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

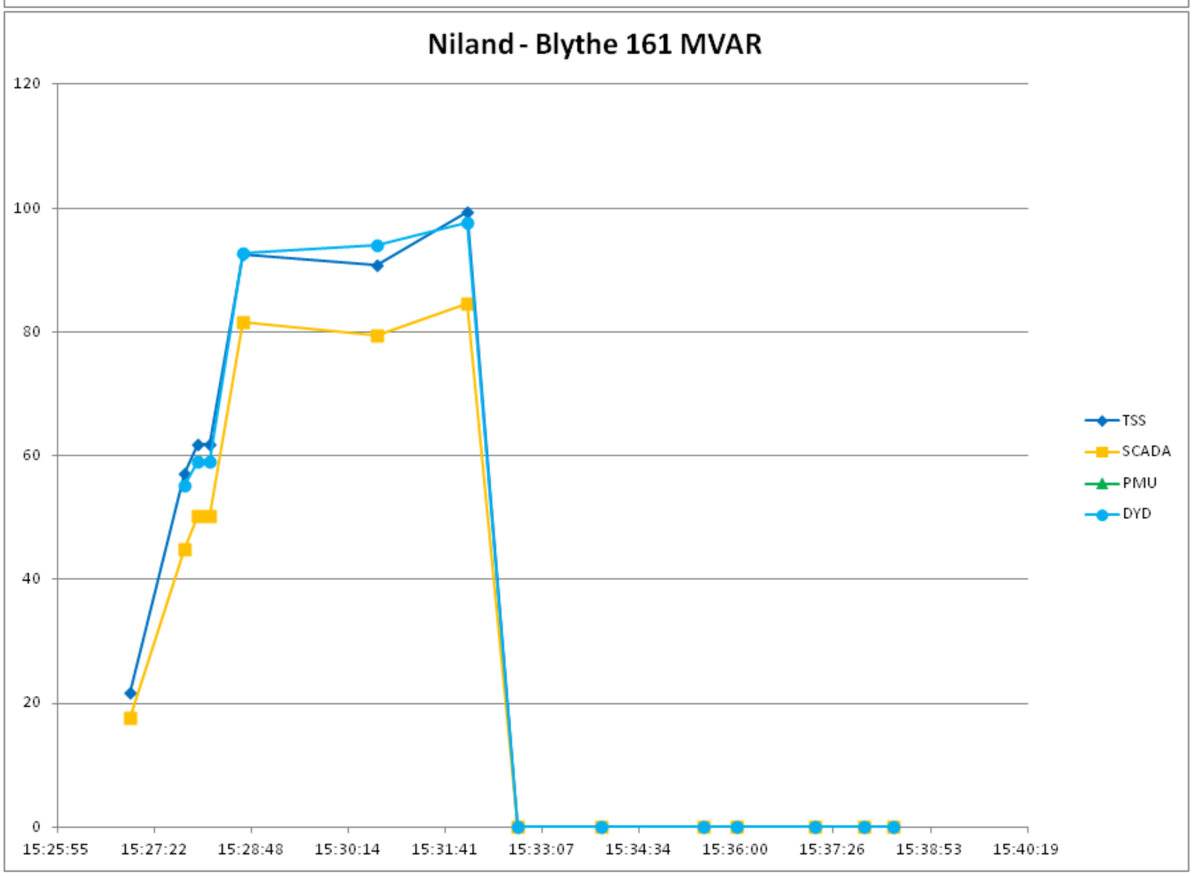

SW DESERT IMPORT MW
1500
1000
500
0
-500
-1000
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

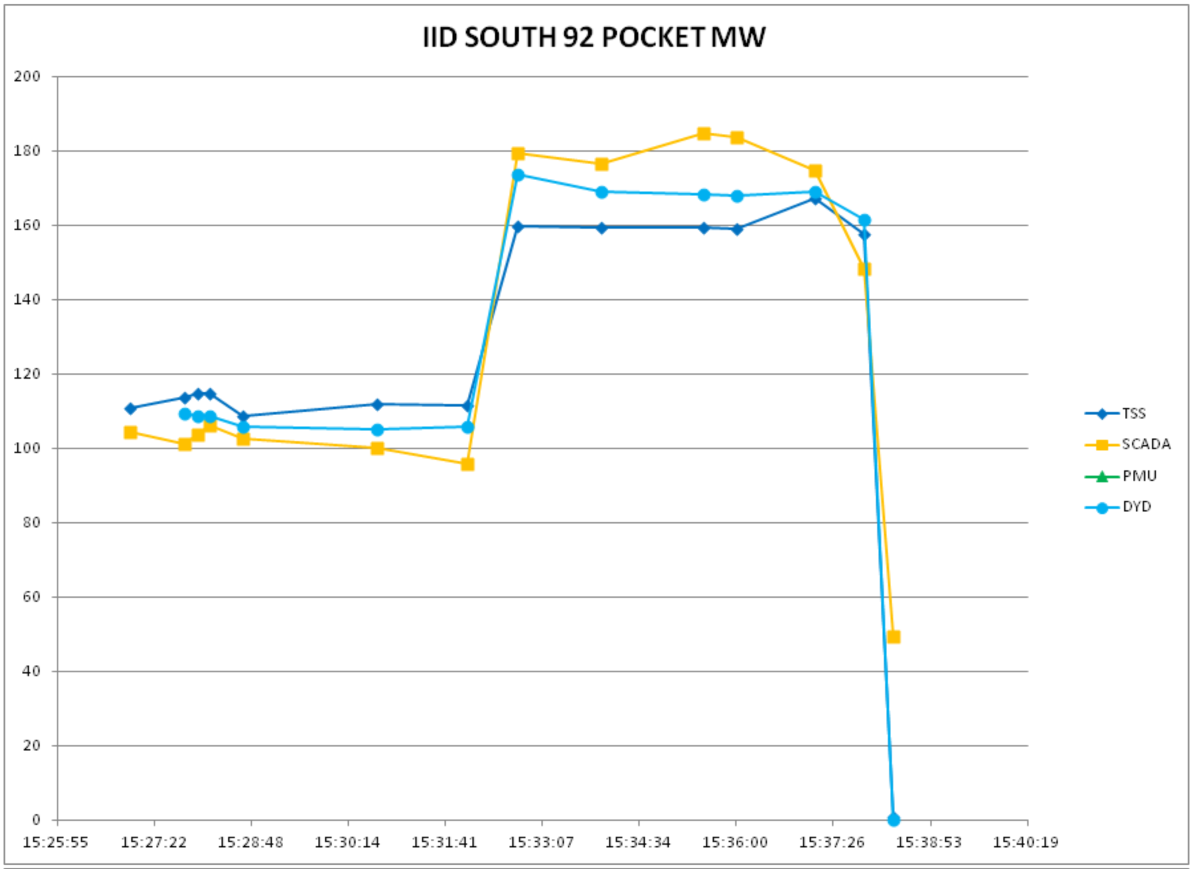

SW DESERT IMPORT MVAR
300
250
200
150
100
50
0
-50
-100
-150
-200
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

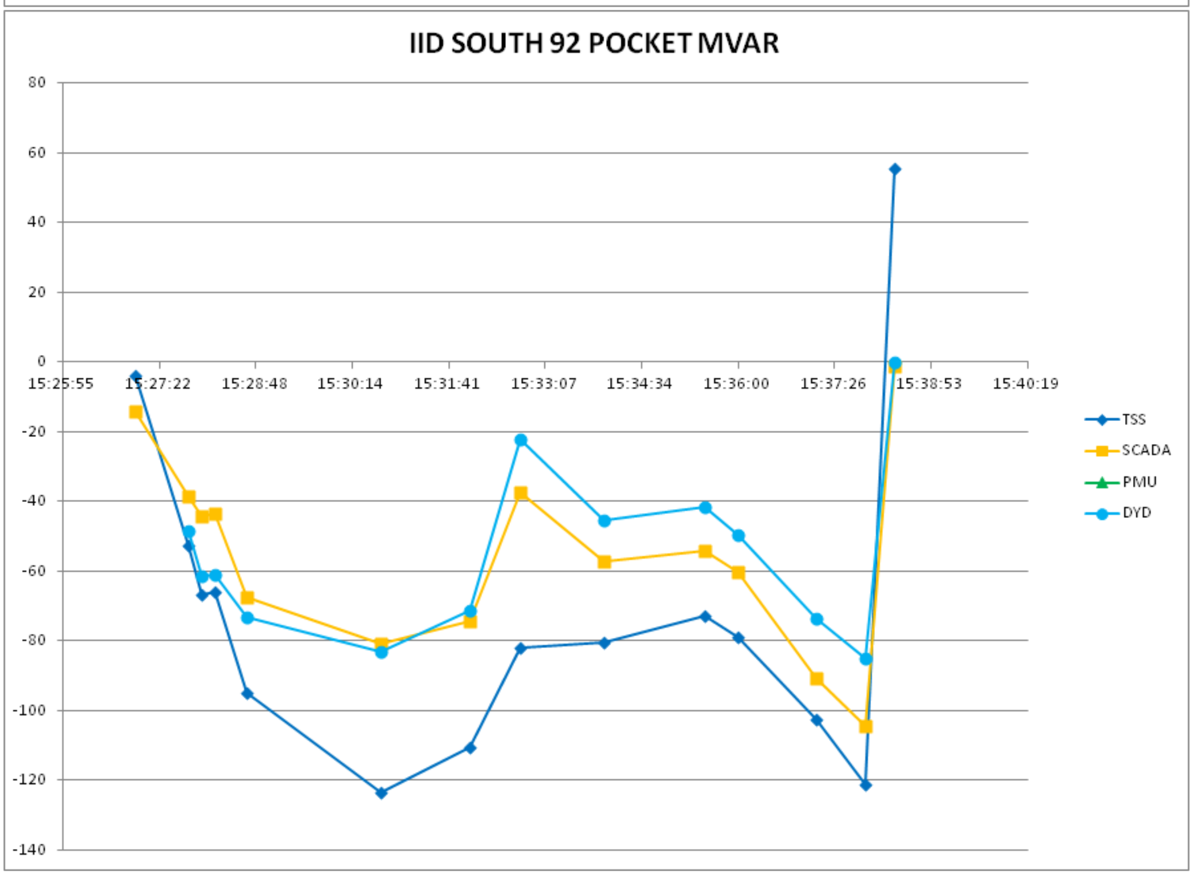

IID NORTH 92 POCKET MW
Differences due to SCADA measurement error at Coachella Valley and Ramon
TSS
SCADA
PMU
DYD

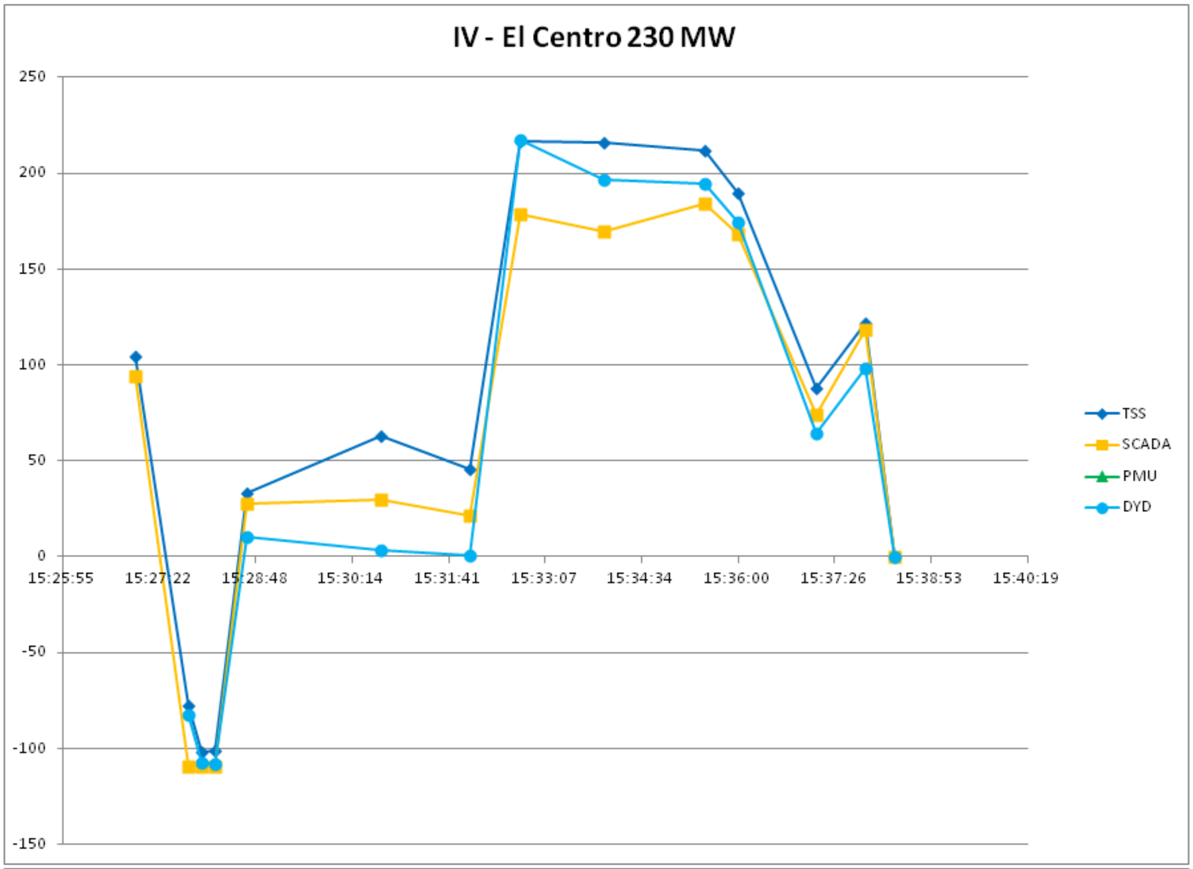

IID NORTH 92 POCKET MVAR
TSS
SCADA
PMU
DYD

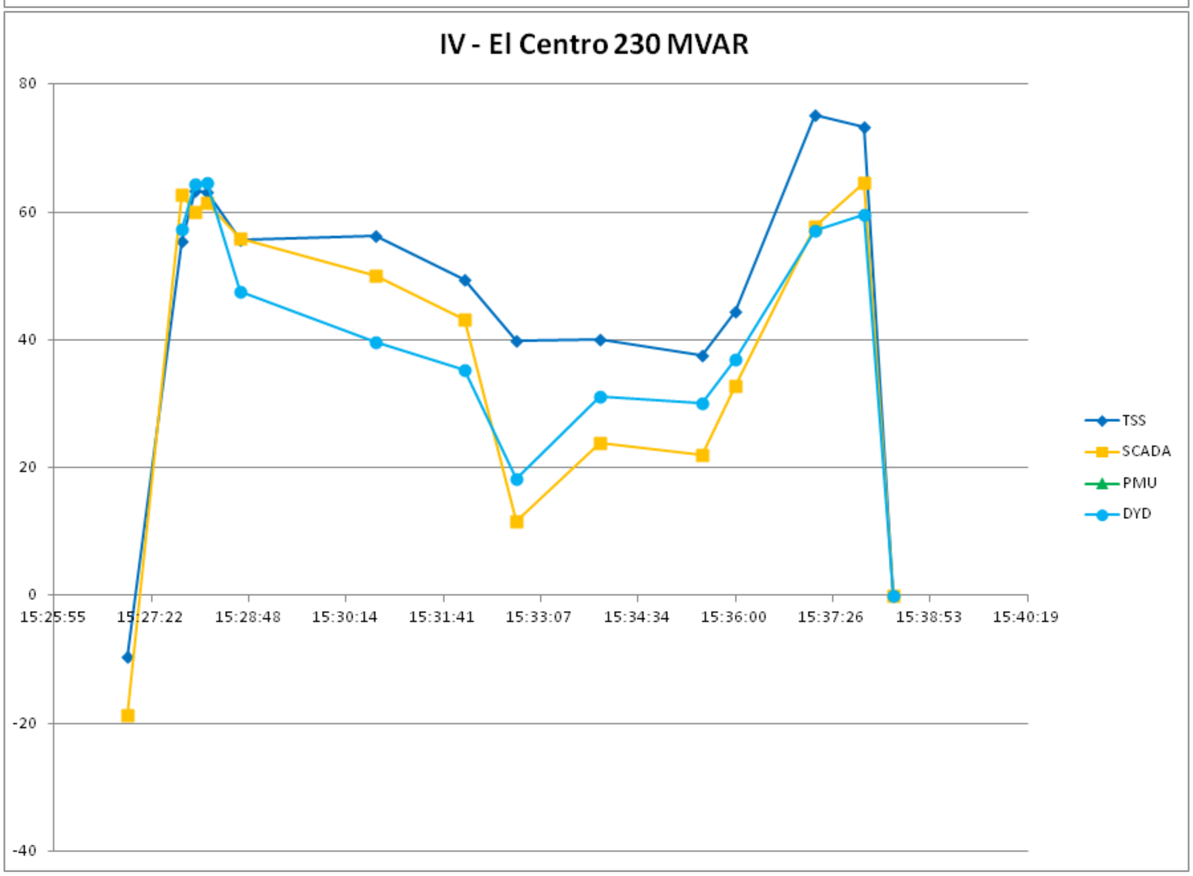

Niland - Blythe 161 MW
0
-20
-40
-60
-80
-100
-120
-140
-160
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

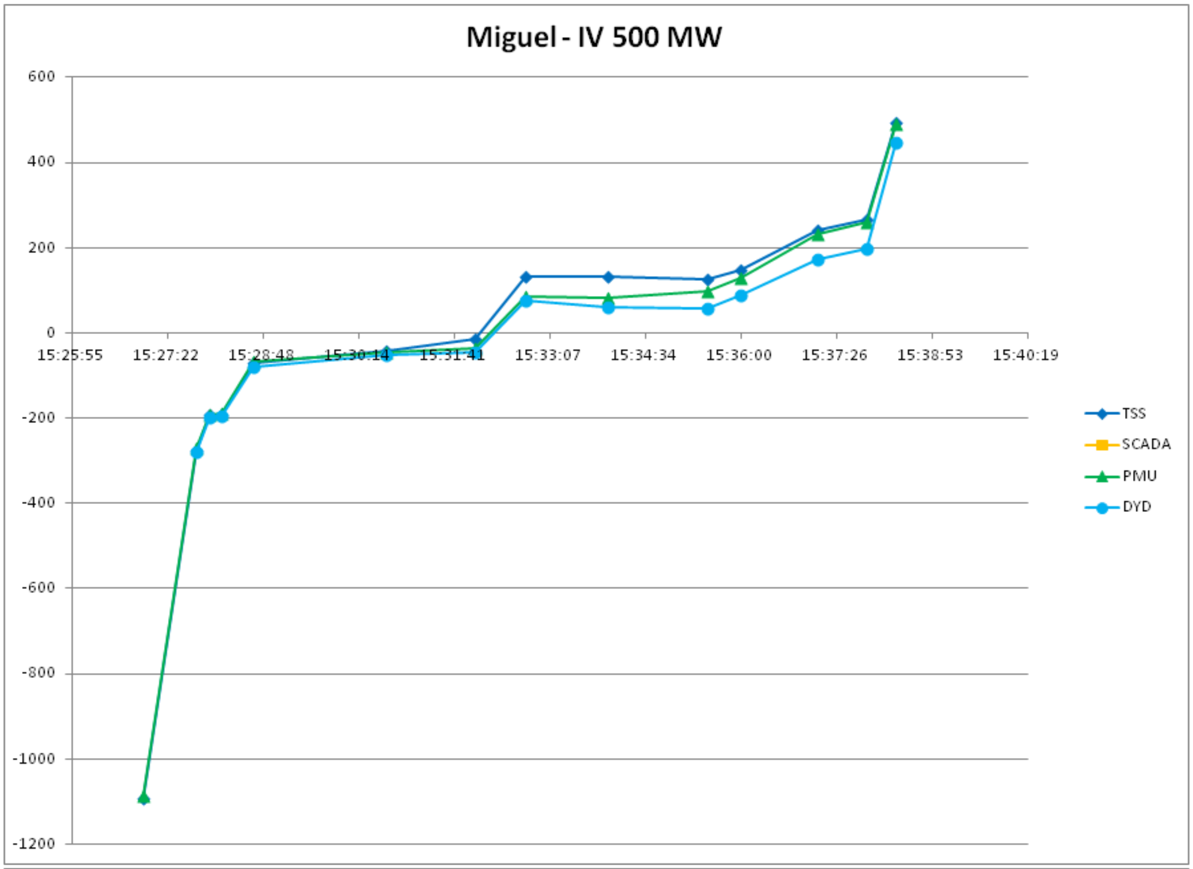

Niland - Blythe 161 MVAR
120
100
80
60
40
20
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

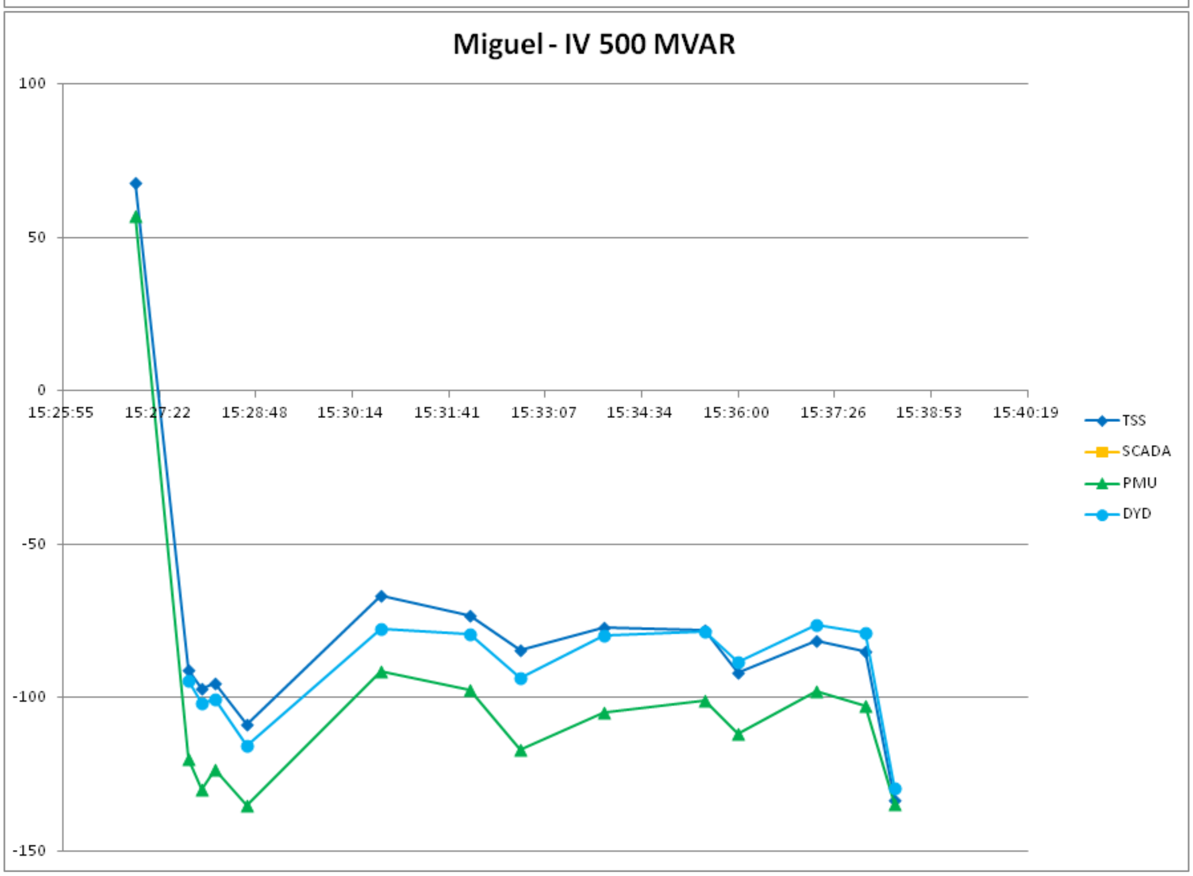

IID SOUTH 92 POCKET MW
200
180
160
140
120
100
80
60
40
20
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

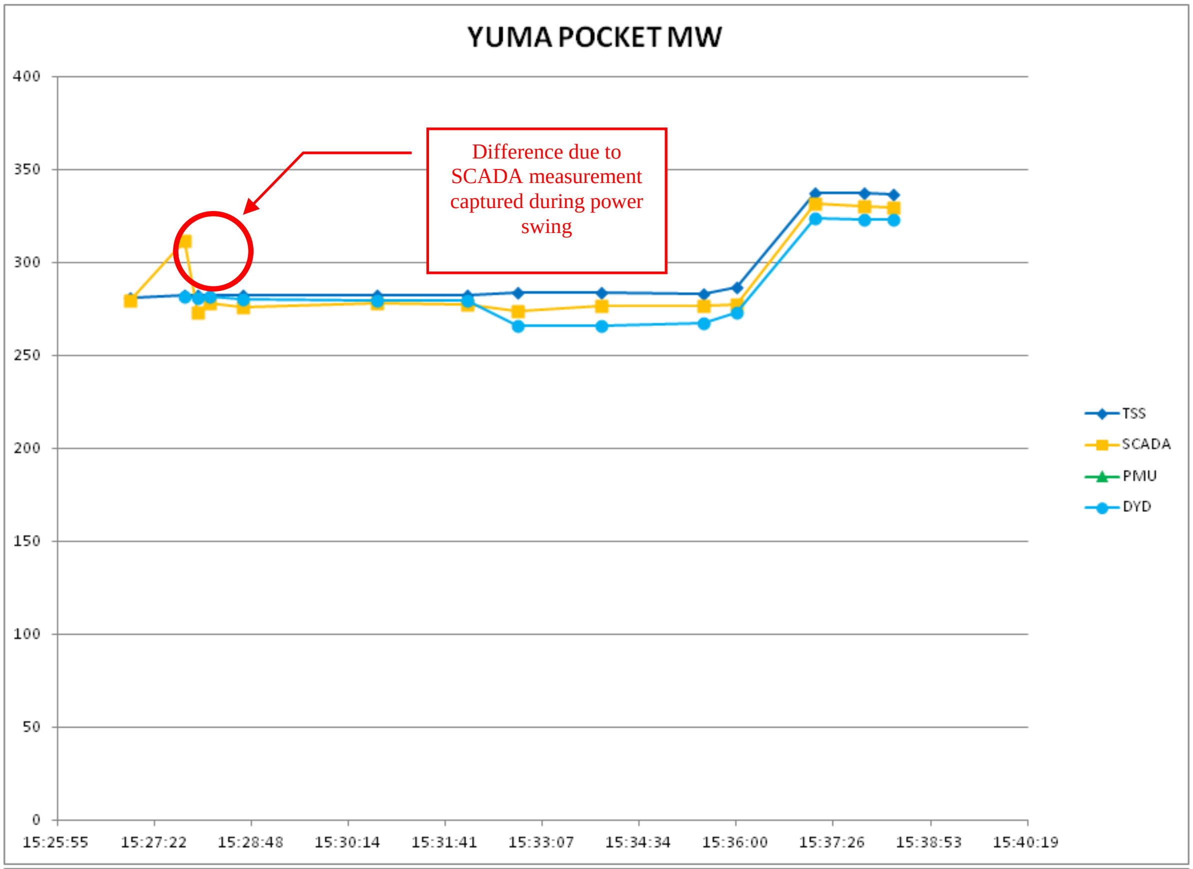

IID SOUTH 92 POCKET MVAR
80
60
40
20
0
-20
-40
-60
-80
-100
-120
-140
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

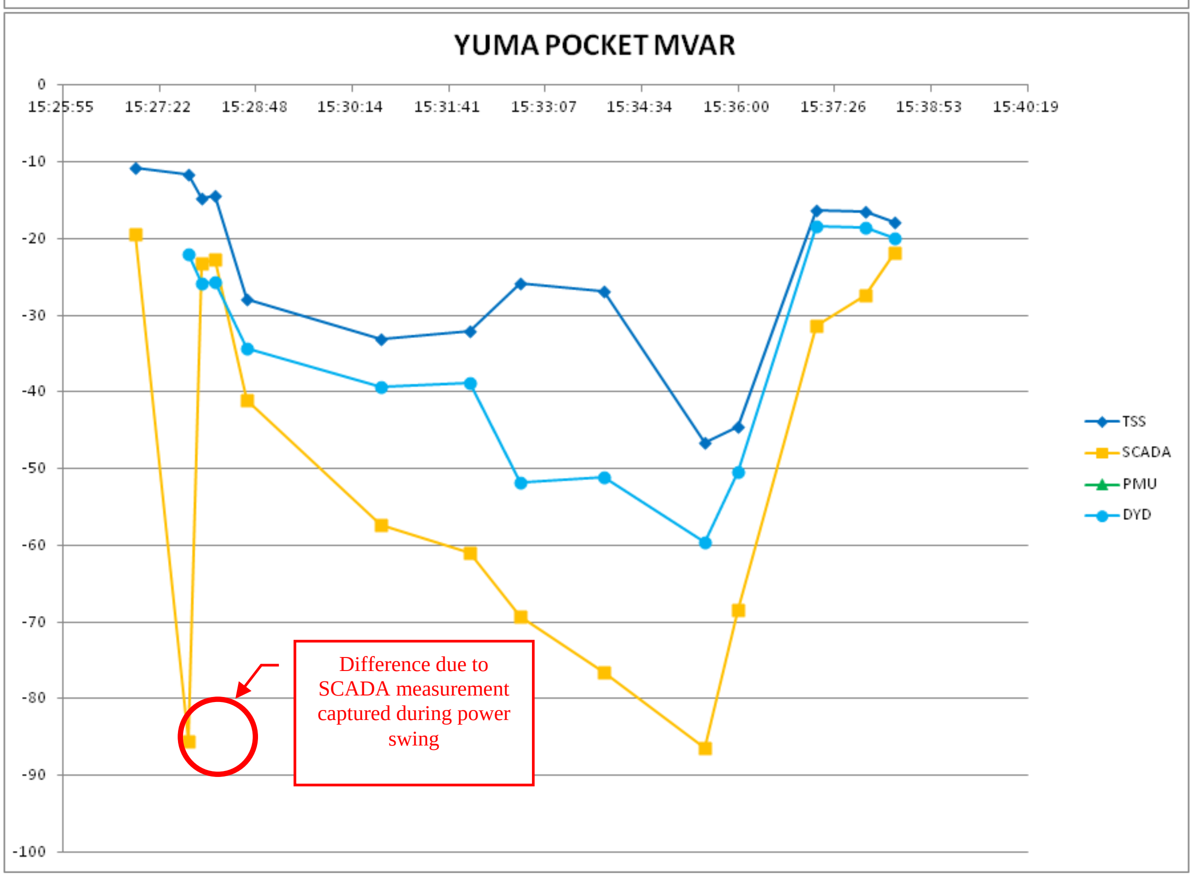

IV - El Centro 230 MW
250
200
150
100
50
0
-50
-100
-150
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

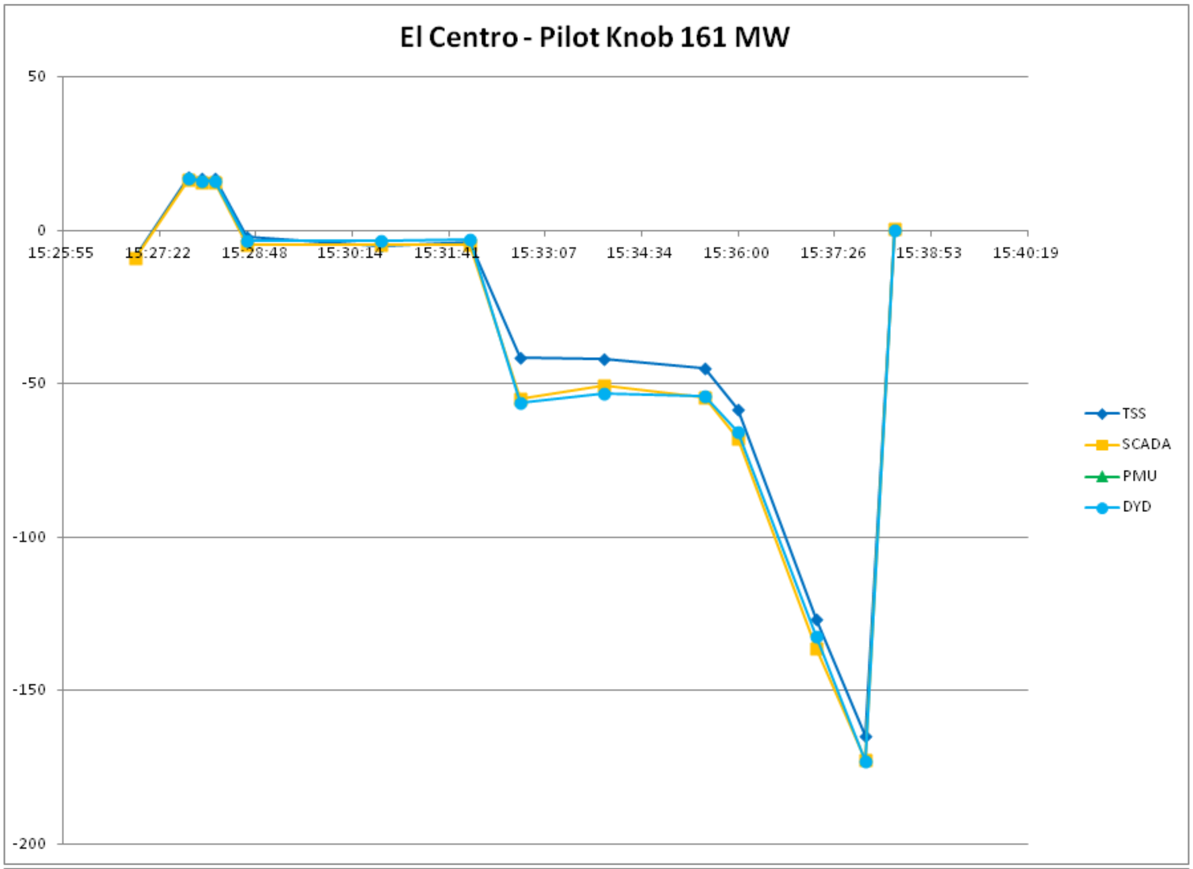

IV - El Centro 230 MVAR
80
60
40
20
0
-20
-40
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

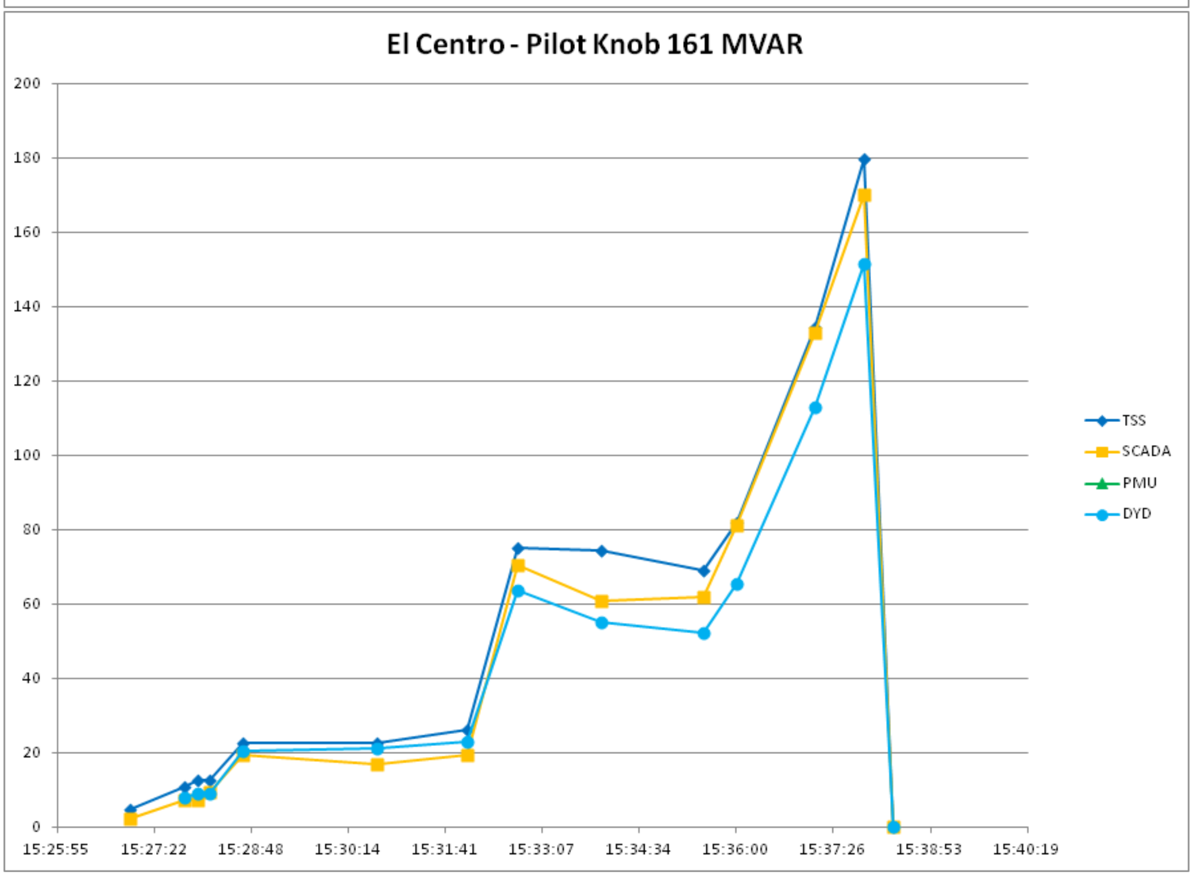

Miguel - IV 500 MW
600
400
200
0
-200
-400
-600
-800
-1000
-1200
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

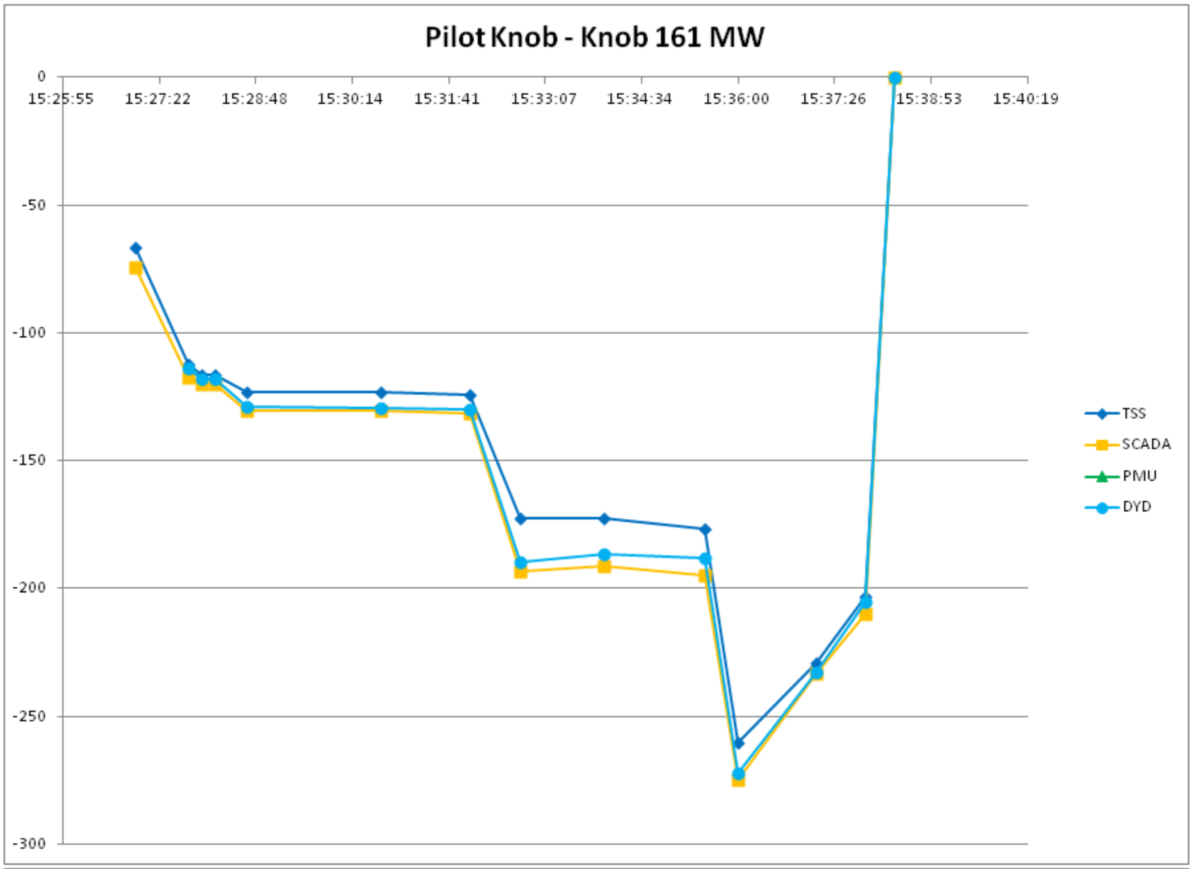

Miguel - IV 500 MVAR
100
50
0
-50
-100
-150
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

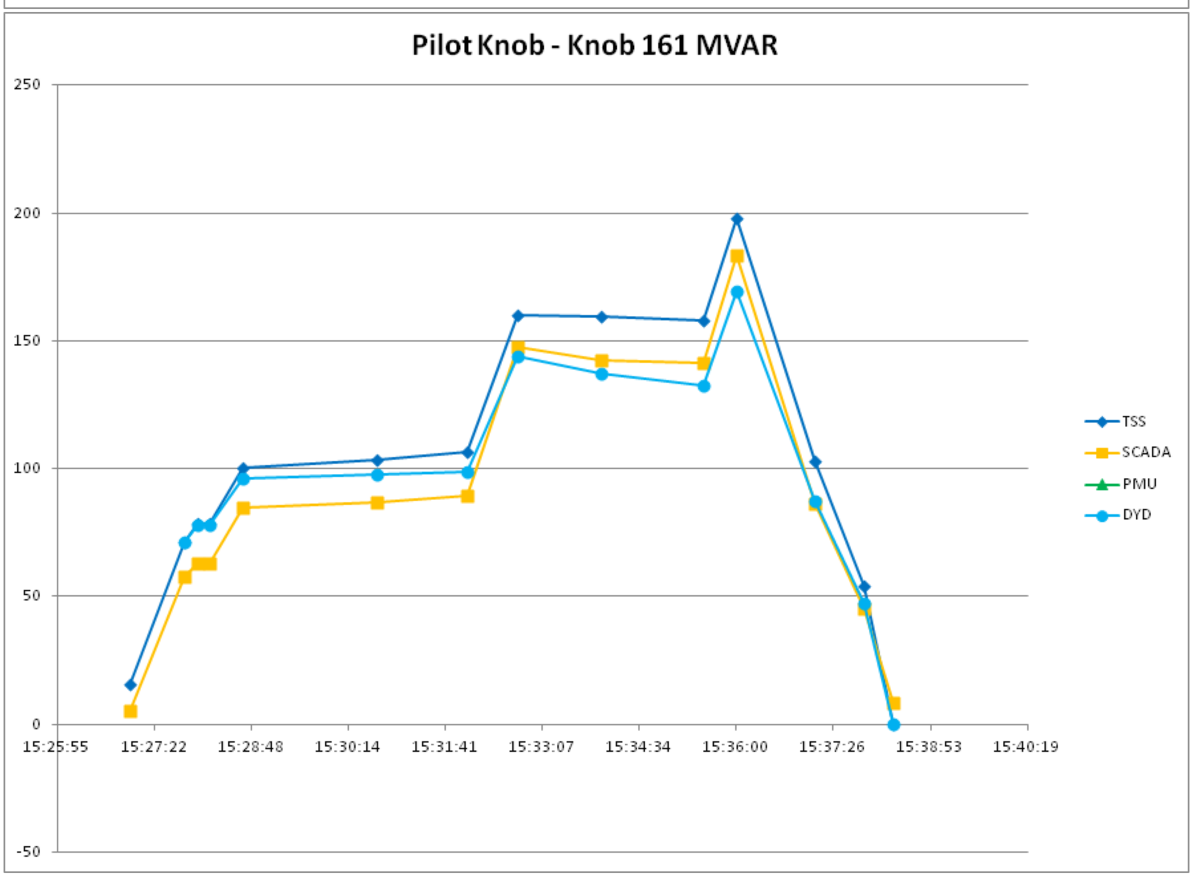

YUMA POCKET MW
Difference due to SCADA measurement captured during power swing
400
350
300
250
200
150
100
50
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

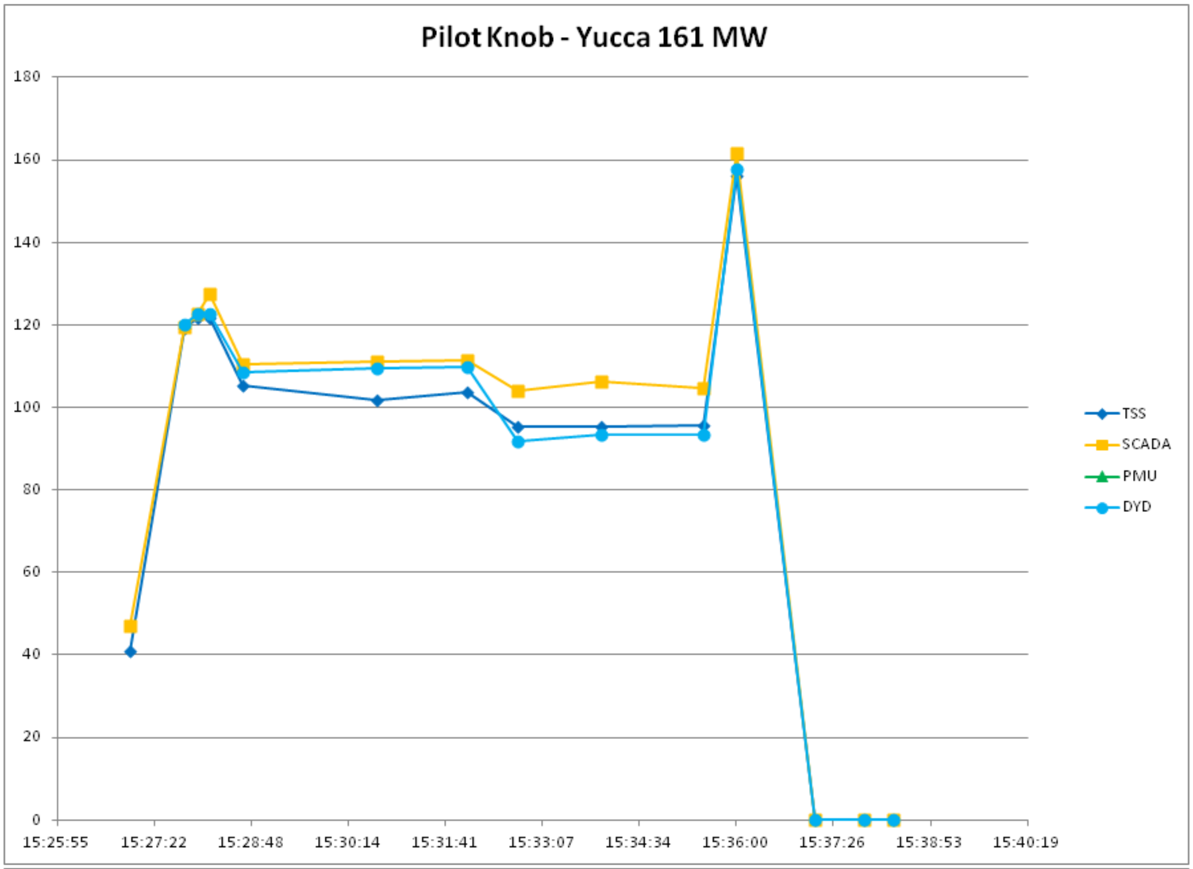

YUMA POCKET MVAR
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
-10
-20
-30
-40
-50
-60
-70
-80
-90
-100
Difference due to SCADA measurement captured during power swing
TSS
SCADA
PMU
DYD

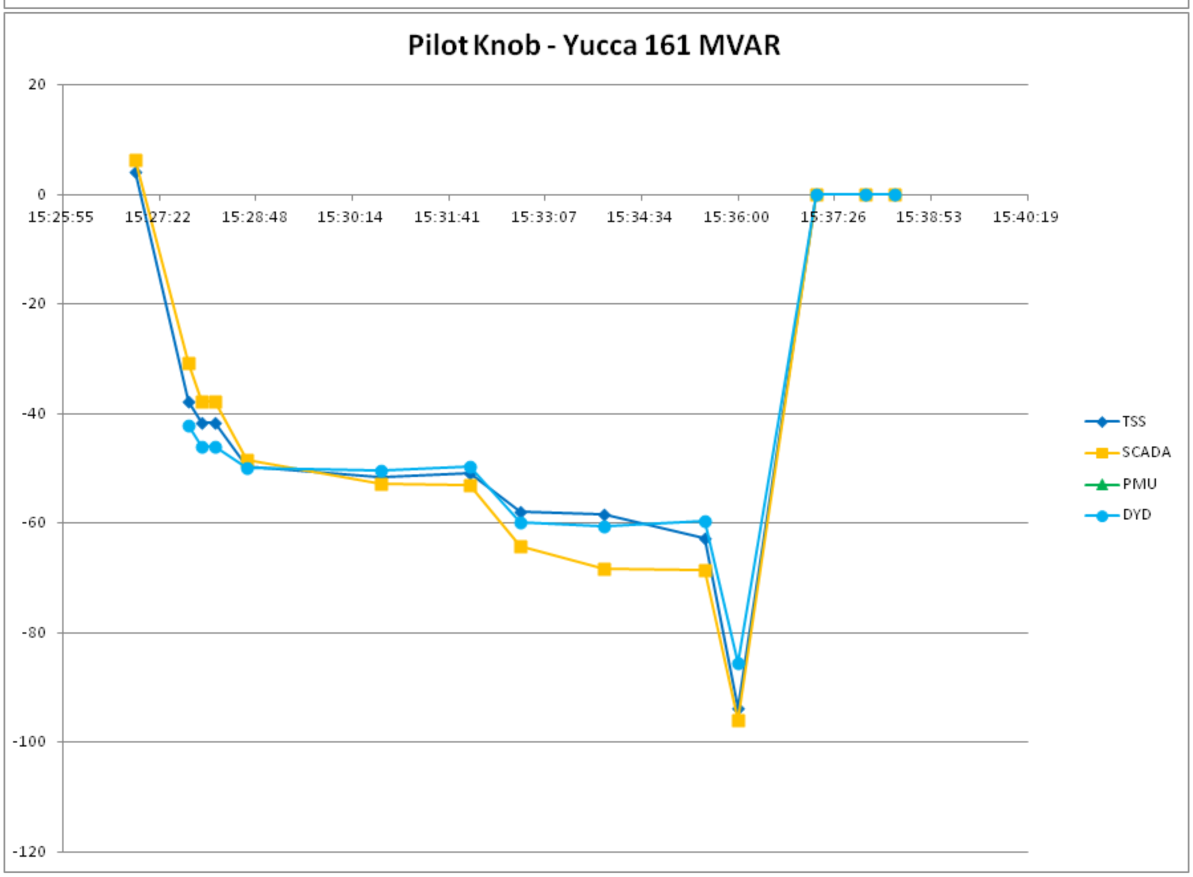

El Centro - Pilot Knob 161 MW
50
0
-50
-100
-150
-200
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

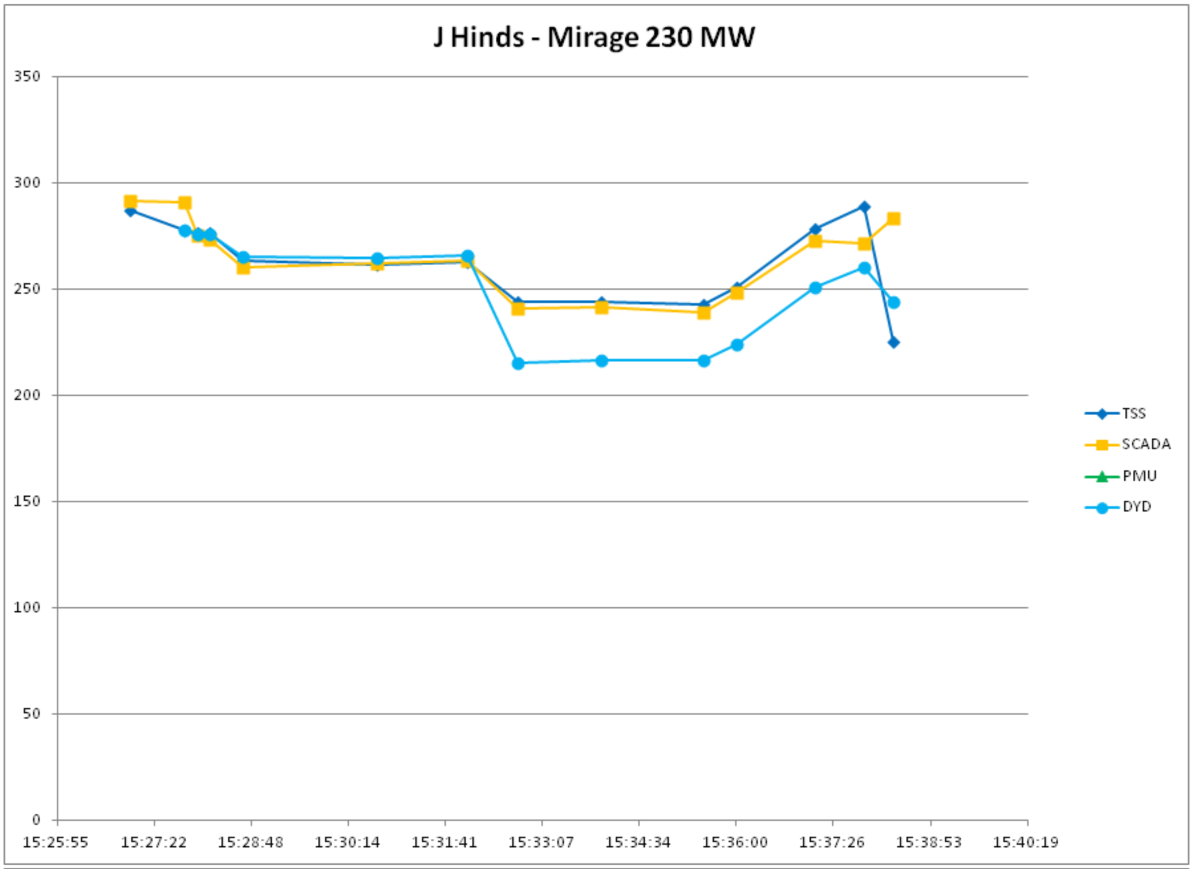

El Centro - Pilot Knob 161 MVAR
200
180
160
140
120
100
80
60
40
20
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

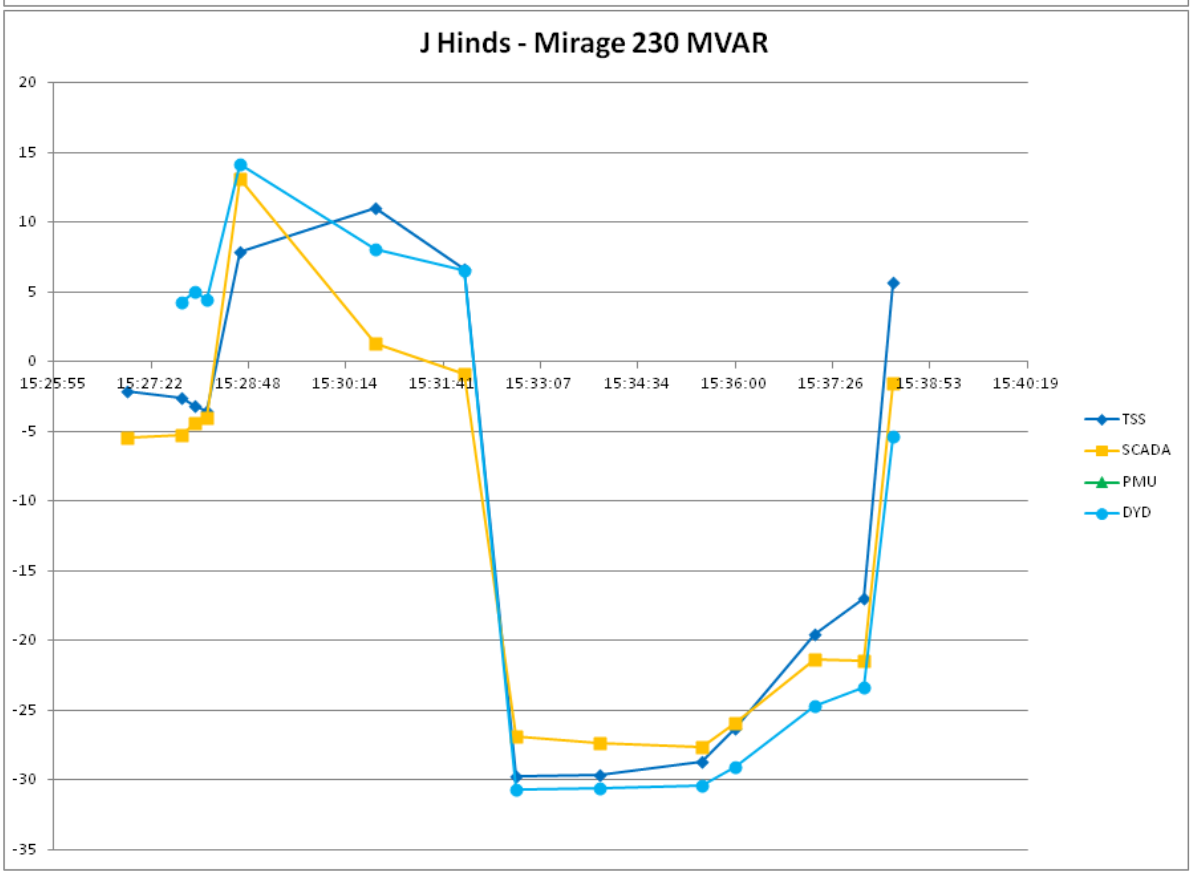

Pilot Knob - Knob 161 MW
0
-50
-100
-150
-200
-250
-300
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

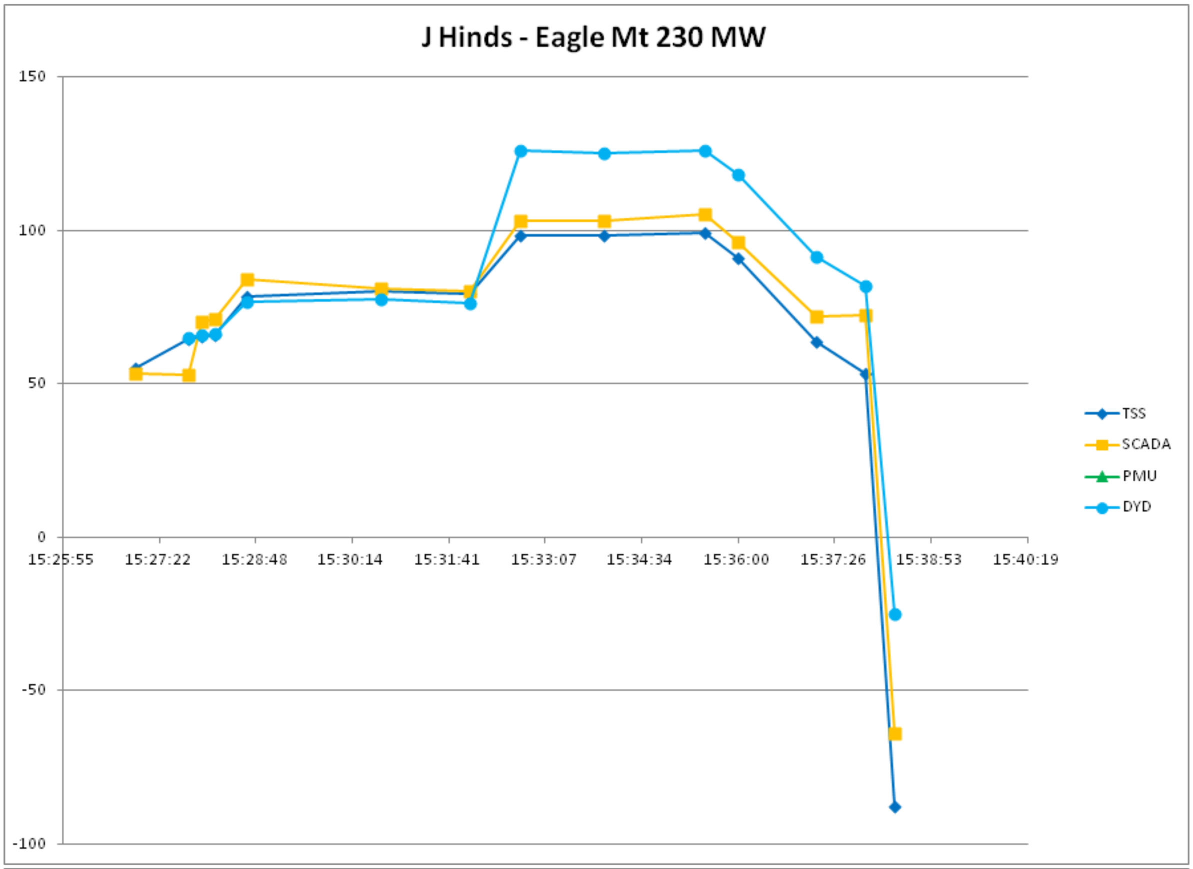

Pilot Knob - Knob 161 MVAR
250
200
150
100
50
0
-50
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

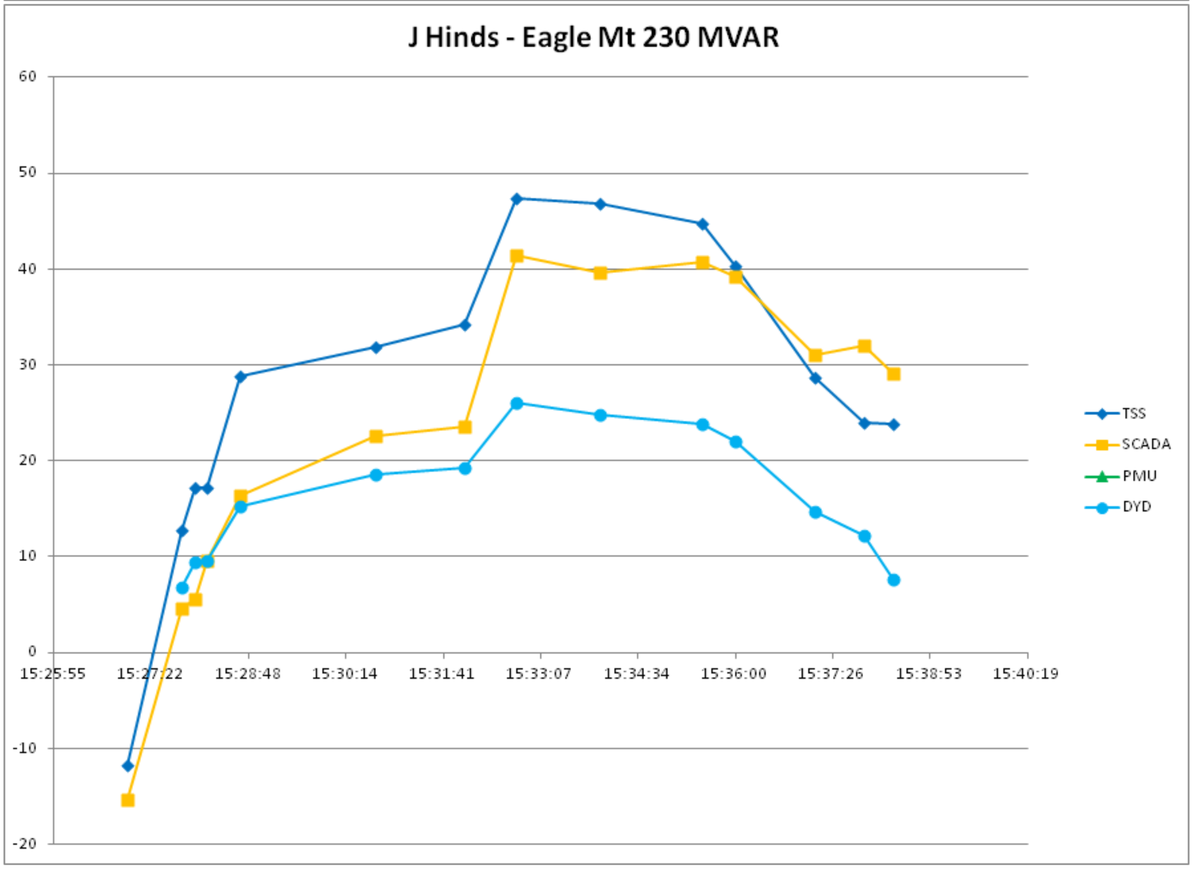

Pilot Knob - Yucca 161 MW
180
160
140
120
100
80
60
40
20
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD


Pilot Knob - Yucca 161 MVAR
20
0
-20
-40
-60
-80
-100
-120
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD


J Hinds - Mirage 230 MW
350
300
250
200
150
100
50
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD


J Hinds - Mirage 230 MVAR
20
15
10
5
0
-5
-10
-15
-20
-25
-30
-35
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD


J Hinds - Eagle Mt 230 MW
150
100
50
0
-50
-100
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD


J Hinds - Eagle Mt 230 MVAR
60
50
40
30
20
10
0
-10
-20
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

Key facilities and interfaces in the affected area were generally benchmarked to within 5% or 10 MVA accuracy to the measured data.

		Base Case					15:28:11				
Key Facility/ Interface	**Type**	**Measured**	**Power Flow Simulation**	**Delta (Value)**	**Delta (%)**		**Measured**	**Power Flow Simulation**	**Delta (Value)**	**Delta (%)**	**Dynamics Simulation**
WECC Path 44	**MVA**	**1310.25**	**1323.61**	**-13.36**	**-1.02%**		**2453.57**	**2471.50**	**-17.93**	**-0.73%**	**2457.19**
	MW	1296.85	1292.09	4.77	0.37%		2434.48	2452.40	-17.92	-0.74%	2442.90
	MVAR	-186.93	-287.17	100.24	-53.63%		-305.49	-306.68	1.19	-0.39%	-264.64
Southwest California Desert Imports	**MVA**	**1328.45**	**1336.38**	**-7.93**	**-0.60%**		**333.50**	**349.91**	**-16.41**	**-4.92%**	**347.90**
	MW	1301.35	1307.75	-6.40	-0.49%		310.76	316.68	-5.92	-1.90%	310.03
	MVAR	266.96	275.16	-8.19	-3.07%		-121.02	-148.82	27.80	-22.97%	-157.84
IID North 92 kV System	**MVA**	**475.15**	**476.81**	**-1.66**	**-0.35%**		**416.84**	**480.17**	**-63.32**[115]	**-15.19%**[116]	**466.78**
	MW	471.60	473.23	-1.63	-0.35%		414.58	477.61	-63.04	-15.21%	464.39
	MVAR	-58.01	-58.31	0.30	-0.52%		-43.43	-49.46	6.03	-13.88%	-47.15
Niland - Blythe 161 kV Line	**MVA**	**67.49**	**69.45**	**-1.97**	**-2.92%**		**108.41**	**118.34**	**-9.93**	**-9.16%**	**117.37**
	MW	-65.13	-65.99	0.86	-1.32%		-96.10	-100.93	4.83	-5.02%	-101.43
	MVAR	17.68	21.67	-3.99	-22.56%		50.17	61.79	-11.62	-23.16%	59.07
IID South 92 kV System	**MVA**	**105.60**	**110.97**	**-5.37**	**-5.08%**		**114.63**	**132.43**	**-17.80**[117]	**-15.53%**[118]	**124.85**
	MW	104.67	110.91	-6.24	-5.96%		106.14	114.84	-8.70	-8.20%	108.87
	MVAR	-14.03	-3.73	-10.30	73.42%		-43.29	-65.93	22.65	-52.31%	-61.12
Imperial Valley - El Centro 230 kV Line ("S" Line)	**MVA**	**96.08**	**105.20**	**-9.12**	**-9.49%**		**125.31**	**119.52**	**5.79**	**4.62%**	**302.90**
	MW	94.24	104.76	-10.53	-11.17%		-109.22	-101.41	-7.81	7.15%	302.90
	MVAR	-18.75	-9.58	-9.17	48.89%		61.42	63.26	-1.83	-2.98%	0.05
Miguel - Imperial Valley 500 kV Line	**MVA**	**1088.80**	**1095.22**	**-6.42**	**-0.59%**		**225.19**	**214.12**	**11.07**	**4.91%**	**77.98**
	MW	-1087.30	-1093.10	5.80	-0.53%		-188.50	-191.82	3.32	-1.76%	77.31

115 Large differences due to SCADA measurement errors at Coachella Valley and Ramon

116 Id.

117 The team experienced difficulty in calibrating the MVAR flows in this area, but are generally confident in the benchmarking because the MW values are within 10 MW. The MVA differences in the model appear to increase during this event. The representation of the system in this area of the model appears to assume that the IID South 92 kV system is a load serving local network. However, the actual transmission system operates in parallel with the rest of the BPS. It was difficult to calibrate the flows at the 92 kV to 161 kV interfaces because of the differences between the representation of the system in the model versus the parallel nature of the actual system.

118 Id.

	MVAR	57.18	68.13	-10.94	-19.14%		-123.20	-95.15	-28.05	22.77%	-10.26
Yuma Pocket	**MVA**	**280.78**	**281.61**	**-0.83**	**-0.30%**		**279.55**	**283.18**	**-3.63**	**-1.30%**	**282.79**
	MW	280.11	281.41	-1.30	-0.46%		278.63	282.81	-4.18	-1.50%	281.63
	MVAR	-19.46	-10.70	-8.76	45.00%		-22.66	-14.46	-8.20	36.20%	-25.68
El Centro - Pilot Knob 161 kV Line	**MVA**	**9.15**	**9.83**	**-0.69**	**-7.51%**		**18.27**	**21.17**	**-2.90**	**-15.87%**	**18.51**
	MW	-8.90	-8.60	-0.30	3.40%		15.73	17.04	-1.31	-8.33%	16.10
	MVAR	2.09	4.76	-2.68	-127.99%		9.29	12.56	-3.27	-35.17%	9.14
Pilot Knob - Knob 161 kV Line	**MVA**	**74.27**	**68.50**	**5.77**	**7.76%**		**135.67**	**140.14**	**-4.46**	**-3.29%**	**141.54**
	MW	-74.06	-66.62	-7.44	10.05%		-120.25	-116.14	-4.11	3.42%	-118.13
	MVAR	5.54	15.94	-10.40	-187.80%		62.83	78.42	-15.59	-24.81%	77.96
Pilot Knob - Yucca 161 kV Line	**MVA**	**47.34**	**41.17**	**6.18**	**13.05%**		**132.82**	**128.54**	**4.28**	**3.22%**	**130.96**
	MW	46.92	40.94	5.98	12.74%		127.39	121.67	5.72	4.49%	122.63
	MVAR	6.33	4.30	2.03	32.04%		-37.60	-41.46	3.87	-10.28%	-45.95
Julian Hinds - Mirage 230 kV Line	**MVA**	**291.92**	**287.50**	**4.42**	**1.51%**		**273.49**	**276.69**	**-3.21**	**-1.17%**	**276.32**
	MW	291.87	287.49	4.38	1.50%		273.46	276.67	-3.21	-1.18%	276.29
	MVAR	-5.45	-2.12	-3.33	61.10%		-3.98	-3.48	-0.49	12.43%	4.45
Julian Hinds - Eagle Mountain 230 kV Line	**MVA**	**55.47**	**56.59**	**-1.12**	**-2.01%**		**71.70**	**68.07**	**3.63**	**5.06%**	**66.96**
	MW	53.29	55.35	-2.07	-3.88%		71.06	65.89	5.18	7.28%	66.26
	MVAR	-15.43	-11.78	-3.64	23.62%		9.56	17.13	-7.57	-79.17%	9.64

Appendix E: Inquiry Team Members

FERC Staff

Office of Enforcement
Heather Polzin
Jeremy Medovoy
Catherine Collins
Samuel Backfield
Thomas Lemon
Cherise Ojo

Office of Electric Reliability
Alan Phung
Alireza Ghassemian
Boris Voynik
David Burnham
Eddy Lim
Gilbert Lowe
Jacob Lucas
John Spivak
Ken Githens
Kent Davis
Leonard Chamberlin
Louise Nutter
Mahmood Mirheydar
Michelle Veloso
Monica Taba
Pablo Ovando
Perry Servedio
Sasan Jalali
Terrance Clingan
Terrence Simon
Thomas Reina
Victor Barry

Office of Energy Policy & Innovation
Mary Cain

NERC Staff

Ben McMillan
Bob Cummings
Chris McManus
Dave Nevius
Dmitry Kosterev (Technical Consultant, from BPA)
Earl Shockley
Ed Ruck
Eric Allen
Greg Henry
James Merlo
Jim Griffith
Jim Robinson
Jule Tate
Kimberly Mielcarek
Mark Vastano
Phil Tatro
Phil Winston (Technical Consultant, from Southern Company)
Roman Carter
Terry Brinker

Department of Energy Liason
James McGlone

Nuclear Regulatory Commission Staff
Singh Matharu

Exhibit H

Summary of Development and Complete Record of Development

Summary of Development

Summary of Development History

The development record for proposed Reliability Standards IRO-018-1 and IRO-010-1 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 of 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 I.

II. Standard Development History

A. Standard Authorization Request Development

In April 2015, the Standards Committee (SC) appointed a new Standard Authorization Request (SAR) Drafting Team (DT) to resume development on Project 2009-02 Real-time Monitoring and Analysis Capabilities. This project originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBP Task Force) but was paused in 2011. In determining the recommended scope for standards development, the SAR DT reviewed previous work associated with this project along with recommendations from the 2008 RTBP Task Force report, FERC Order No. 693 directives, and recommendations from the 2011 Southwest Outage Report. Additionally, an industry technical conference was conducted on June 4, 2015, to solicit feedback and recommendations from

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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.

industry stakeholders. A SAR for Project 2009-02 was submitted in June 18, 2015. The SAR and a supporting white paper were posted for 30-day formal comment from July 16, 2015 through August 17, 2015. The SC accepted the SAR on September 23, 2015.

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

Proposed Reliability Standards IRO-018-1 and TOP-010-1 were posted for a 45-day formal comment period from September 24, 2015 through November 9, 2015, with parallel initial ballots and non-binding polls held during the last 10 days of the comment period from October 30, 2015 through November 9, 2015. Several documents were posted for guidance with the first draft, including the Unofficial Comment Form, the SAR, the SAR Justification White Paper, the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) Justification document, and the Consideration of Directives document. The initial ballot for IRO-018-1 received 84.59% quorum, and 47.36% approval. The initial ballot for TOP-010-1 received 84.49% quorum, and 48.01% approval. The Non-Binding Poll for IRO-018-1 received 82.71% quorum and 54.61% of supportive opinions. The Non-Binding Poll for TOP-010-1 received 83.94% quorum and 56.25% of supportive opinions. There were 42 sets of responses, including comments from approximately 133 different individuals and approximately 102 companies, representing 8 of the 10 industry segments.[3]

C. Second Posting- Comment Period, Additional Ballots and Non-Binding Polls

Proposed Reliability Standards IRO-018-1 and TOP-010-1 were posted for a 45-day formal comment period from December 10, 2015 through January 26, 2016, with parallel additional ballots and nonbinding polls held during the last 10 days of the comment period from

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[3] NERC, *Consideration of Comments*, Project 2009-02, (December 8, 2015), *available at* http://www.nerc.com/pa/Stand/Project%20200902%20Rela%20Time%20Monitotring%20Analysis%20Capa/2009-02_RTMAC_Consideration_of_comments_120815.pdf.

January 15, 2016 through January 26, 2016.[4] The additional ballot for IRO-018-1 reached quorum at 82.88% of the ballot pool, and received 72.14% approval. The additional ballot for TOP-010-1 reached quorum at 82.18% of the ballot pool, and received 68.01% approval. The related Non-Binding Poll for IRO-018-1 reached quorum 81.95% of the ballot pool, and 81.76% of supportive opinions. The related Non-Binding Poll for TOP-010-1 reached quorum 81.02% of the ballot pool, with 76.27% of supportive opinions. There were 38 sets of responses, including comments from approximately 93 different individuals and approximately 69 companies, representing 7 of the 10 industry segments.[5]

D. Final Ballot

Proposed Reliability Standards IRO-018-1 and TOP-010-1 were posted for a 10-final ballot period from February 17, 2016 through February 26, 2016. The ballot for the proposed Reliability Standard IRO-018-1 and associated documents reached quorum at 88.36% of the ballot pool, and the standard received sufficient affirmative votes for approval, receiving support from 75.68% of the voters. The ballot for the proposed Reliability Standard TOP-010-1 and associated documents reached quorum at 87.79% of the ballot pool, and the standard received sufficient affirmative votes for approval, receiving support from 73.86% of the voters.

E. Board of Trustees Adoption

Proposed Reliability Standards IRO-018-1 and TOP-010-1 were adopted by the NERC Board of Trustees on May 5, 2016.

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4 The ballots and non-binding polls were extended an additional day from January 25, 2016 to reach quorum.

5 NERC, *Consideration of Comments*, Project 2009-02, (February 17, 2016), *available at* http://www.nerc.com/pa/Stand/Project%20200902%20Rela%20Time%20Monitotring%20Analysis%20Capa/Consideration_of_Comments_Feb_12_rev.pdf.

Complete Record of Development History

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Related Files

Status

Final ballots for **IRO-018-1 - Reliability Coordinator Real-time Monitoring and Analysis Capabilities** and **TOP-010-1 - Real-time Reliability Monitoring and Analysis Capabilities** concluded **8 p.m. Eastern, Friday, February 26, 2016**. The voting results can be accessed via the links below. The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

Project 2009-02 is included in the 2015-2017 Reliability Standards Development Plan (RSDP) approved by the NERC Board of Trustees (Board) on November 13, 2014. Formal development of this project was paused in 2011 and has resumed to address outstanding Federal Energy Regulatory Commission (FERC) directives and issues that were not consolidated into Project 2014-03 TOP/IRO Revisions.

Project 2009-02 was initiated in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). From 2009 to 2011, a SAR drafting team developed a SAR and technical white paper to establish requirements for the "functionality, performance, and maintenance of Real-time Monitoring and Analysis Capabilities." Since that time, new TOP and IRO standards have been developed that affect the scope of Project 2009-02.

Standard(s) Affected - Two new standards are being proposed: IRO-018-1 - Reliability Coordinator Real-time Monitoring and Analysis Capabilities and TOP-010-1 - Real-time Reliability Monitoring and Analysis Capabilities.

Purpose/Industry Need

The proposed standards will establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations. The SAR addresses selected recommendations in the RTBPTF Report www.nerc.com/comm/OC/Pages/RTBPTF/Real-time-Tools-Best-Practices-Task-Force.aspx, Federal Energy Regulatory Commission (FERC) Order 693 directives, and Bulk Electric System event reports as explained in the SAR Justification White Paper available at the link in the table below.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft IRO-018-1 Clean **(70)**| Redline to Last Posted **(71)** TOP-010-1 Clean **(72)**| Redline to Last Posted **(73)** Implementation Plan Clean **(74)**| Redline to Last Posted **(75)** **Supporting Materials** Consideration of Directives Clean **(76)**| Redline to Last Posted **(77)**	Final Ballot Updated Info **(78)** Info **(79)** Vote	02/17/16 – 02/26/16	Summary **(80)** Ballot Results: IRO-018-1 **(81)** TOP-010-1 **(82)**	

Draft 2 IRO-018-1 Clean **(48)**| Redline to Last Posted **(49)** TOP-010-1 Clean **(50)**| Redline to Last Posted **(51)** Implementation Plan Clean **(52)**| Redline to Last Posted **(53)** **Supporting Materials** Unofficial Comment Form (Word) **(54)** Standard Authorization Request (SAR) **(55)** SAR Justification White Paper **(56)** VRF/VSL Justification Clean **(57)**| Redline to Last Posted **(58)** Consideration of Directives Clean **(59)**| Redline to Last Posted **(60)**	Additional Ballots and Non-binding Polls Info **(61)** Vote	01/15/16 – 01/25/16* *Ballots and non-binding polls extended an additional day (from 01/25/16) to reach quorum	Summary **(63)** Ballot Results: IRO-018-1 **(64)** TOP-010-1 **(65)** Non-binding Polls Results: IRO-018-1 **(66)** TOP-010-1 **(67)**	
	Comment Period Info **(62)** Submit Comments	12/10/15 - 01/26/16	Comments Received **(68)**	Consideration of Comments **(69)**
Draft Reliability Standard Audit Worksheets (RSAWs) IRO-018-1 TOP-010-1	Info Send RSAW feedback to: RSAWfeedback@nerc.net	12/22/15 - 01/26/16		

Draft 1 IRO-018-1 **(28)** TOP-010-1 **(29)** Implementation Plan **(30)** **Supporting Materials** Unofficial Comment Form (Word) **(31)** Standard Authorization Request (SAR) Clean **(32)**| Redline to Last Posted **(33)** SAR Justification White Paper Clean **(34)**| Redline to Last Posted **(35)** VRF/VSL Justification **(36)** Consideration of Directives **(37)**	Initial Ballots and Non-binding Polls Updated Info **(38)** Info **(39)** Vote	10/30/15 – 11/09/15	Summary **(41)** Ballot Results: IRO-018-1 **(42)** TOP-010-1 **(43)** Non-binding Polls Results: IRO-018-1 **(44)** TOP-010-1 **(45)**	
	Comment Period Info **(40)** Submit Comments	09/24/15 – 11/09/15	Comments Received **(46)**	Consideration of Comments **(47)**
	Join Ballot Pools	09/24/15 - 10/23/15		
Draft Reliability Standard Audit Worksheet (RSAW) IRO-018-1 TOP-010-1	Info Send RSAW feedback to:RSAWfeedback@nerc.net	10/07/15 - 11/09/15		
Standard Authorization Request (SAR) **(22)** **Supporting Materials** Unofficial Comment Form (Word) **(23)** SAR Justification White Paper **(24)**	Comment Period Info **(25)** Submit Comments	7/16/2015 - 8/17/15	Comments Received **(26)**	Consideration of Comments **(27)**

Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(20)**	Info **(21)** Submit Nominations	2/20/2015 - 3/6/2015		
Concept White Paper **(17)** **Supporting Materials** Comment Form (Word) **(18)**	Informal Comment Period Info **(19)** Submit Comments	2/16/2011 - 4/4/2011		
Final SAR Version 3 Clean **(15)**| Redline to Last Posting **(16)**	**For Standards Committee Approval**			
Draft 2 - SAR Draft SAR Version 2 Clean **(9)** | Redline **(10)** **Supporting Materials** Comment Form (Word) **(11)**	Comment Period Info **(12)** Submit Comments	1/19/2010 - 2/18/2010	Comments Received **(13)**	Consideration of Comments **(14)**
Proposed SAR for Real-time Tools Draft SAR Version 1 **(3)** **Supporting Materials** Comment Form (Word) **(4)** Real-Time Tools Survey Analysis and Recommendations **(5)**	Comment Period Info **(6)** Submit Comments	6/10/2009 - 7/11/2009	Comments Received **(7)**	Consideration of Comments **(8)**
Project 2009-02 Real-time Tools SAR Drafting Team Nominations **Supporting Materials** Nomination Form (Word) **(1)**	Info **(2)** Submit Nominations	6/9/2009 - 6/25/2009		

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Nomination Form for Real-time Tools SAR Drafting Team (Project 2009-02)

Please use the electronic nomination form located at the link below to submit your nomination by **June 25, 2009** to participate on the SAR Drafting Team. If you have any questions, please contact David Taylor at david.taylor@nerc.net.

http://www.nerc.com/filez/standards/Project2009-02_Real_Time_Tools.html

By submitting the following information you are indicating your willingness and agreement to actively participate in the SAR development process and SAR Drafting Team meetings if appointed to the SAR Drafting Team by the Standards Committee.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Project 2009-02 Real Time Tools - The SAR calls for developing a new standard or standards to establish requirements for the functionality, performance, and management of Real-time tools for Reliability Coordinators, Transmission Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations.

Please briefly describe your experience and qualifications directly related to the issues to be addressed by the Real-time Tools SAR Drafting Team. We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who collectively have experience in real time operations and knowledge of supervisory control and data acquisition (SCADA) and energy management system (EMS) applications used to support real time operations. Experience in developing would be beneficial as the team will be assisting the requester in exploring the gray area between “what” and “how” in this SAR.

Are you currently a member of any NERC or Regional Entity SAR or standard drafting team? If yes, please list each team here.

☐ No

☐ Yes:

Have you previously worked on any NERC or Regional Entity SAR or standard drafting teams? If yes, please list them here. ☐ No ☐ Yes:
Please identify the NERC Reliability Region(s) in which your company operates and for which you are able to represent your company's position relative to the applicable issues while serving on the SAR drafting team:

☐ ERCOT ☐ FRCC	☐ MRO ☐ NPCC	☐ RFC ☐ SERC	☐ SPP ☐ WEC

☐ Not Applicable or None of the Above

Please identify the Industry Segment(s) for which you are able to represent on behalf of your company while serving on the SAR drafting team:

☐	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
☐	Not applicable

Which of the following Functional Entities[1] do you have expertise or responsibilities for which you are able to represent on behalf of your company while serving on the SAR drafting team:

[1] These functions are defined in the NERC Functional Model, which is available on the NERC Web site.

☐ Balancing Authority	☐ Planning Coordinator
☐ Compliance Enforcement Authority	☐ Transmission Operator
☐ Distribution Provider	☐ Transmission Owner
☐ Generator Operator	☐ Transmission Planner
☐ Generator Owner	☐ Transmission Service Provider
☐ Interchange Authority	☐ Purchasing-selling Entity
☐ Load-serving Entity	☐ Resource Planner
☐ Market Operator	☐ Reliability Coordinator

Please 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 which you give us permission to contact in the event it is deemed necessary to do so.

Name and Title:		Office Telephone:	
Organization:		E-mail:	
Name and Title:		Office Telephone:	
Organization:		E-mail:	

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Nomination Period Opens for Standard Authorization Request (SAR) Drafting Team
June 9–25, 2009

Now available at: http://www.nerc.com/filez/standards/Project2009-02_Real_Time_Tools.html

Nominations for SAR Drafting Team (Project 2009-02 — Real-time Tools)

The Standards Committee is seeking industry experts to serve on the Real-time Tools SAR Drafting Team (see project background below). The SAR drafting team will assist the requester in further developing the SAR and considering stakeholder comments.

If you are interested in serving on this SAR drafting team, please complete the following electronic nomination form **by June 25, 2009**: https://www.nerc.net/nercsurvey/Survey.aspx?s=3d8635074fd24fcd92689c04919d9e97

Please contact Dave Taylor at david.taylor@nerc.net with any questions about the team.

Project Background:

According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, dated April 2004, a principal cause of the August 14 blackout was a lack of situational awareness, due in part to inadequate reliability tools. Recommendation 22 of the report states, "Evaluate and adopt better real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate real-time tools and their usage within the industry. The Task Force produced a report, *Real-Time Tools Survey Analysis and Recommendations*, in March 2008 that included recommendations for the functionality, performance, and management of real-time tools.

The SAR addresses selected recommendations in the RTBPTF Report as determined by the Real-time Best Practices Standards Study Group: Project 2009-02. The intent is to describe "what" needs to be done but not "how" to do it.

More information about the project is available on the following page: http://www.nerc.com/filez/standards/Project2009-02_Real_Time_Tools.html

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.

Standard Authorization Request Form

Title of Proposed Standard: Project 2009-02: Real-time Tools	
Request Date: May 11, 2009	
Approved by SC: June 4, 2009	

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name: Jack Kerr	X	New Standard(s)
Primary Contact: Dominion Virginia Power	☐	Revision to existing Standard
Telephone: 1.804.273.3393 Fax: 1.804.273.2405	☐	Withdrawal of existing Standard
E-mail: jack.kerr@dom.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

The new standard or standards will establish requirements for the functionality, performance, and management of Real-time tools for Reliability Coordinators, Transmission Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* dated April 2004, a principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools. In addition, the failure of control computers and alarm systems, incomplete tool sets, and the failure to supply network analysis tools with correct System data on August 14 contributed directly to this lack of situational awareness. Also, the need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations.

Recommendation 22 of the Blackout Report states "Evaluate and adopt better real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate real-time tools and their usage within the industry. The Task Force produced a report "*Real-Time Tools Survey Analysis and Recommendations*", dated March 13, 2008 that included recommendations for the functionality, performance, and management of Real-time tools.

This SAR addresses selected recommendations in the RTBPTF Report as determined by the Real-time Best Practices Standards Study Group: Project 2009-02.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The scope of the SAR is to establish requirements for the functionality, performance, and management of tools used in support of Real-time System Operations. The intent is to describe 'what' needs to be done but not 'how' to do it.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Develop a standard(s) to require the following functionality:

- Alarming – Applications or methods that emit Real-time visible and audible signals to alert Operators to events and conditions affecting the state of the Bulk Electric System (BES).

- Telemetry – Applications and methods that provide status and analog values in Real-time or near-Real-time operation.

- Network analysis – Applications and methods to be used for determining the current state of the system and simulating the impact of 'what if' system events on the current or future state of the system.

Develop a standard(s) to require that responsible entities meet identified performance metrics for the above listed functionalities including but not limited to the consideration of:

- Availability
- Quality

Those entities shall also have procedures for the above listed functionalities including but not limited to the consideration of:

- Change management
- Maintenance coordination
- Failure notification

Revise the Glossary definition of Real-time given that the acquisition and dissemination of operating data has inherent time delays. The current definition of Real-time is: Current time, as opposed to future time.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	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.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	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.
X	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.
X	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 service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	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.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	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.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power 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 of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability 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

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Unofficial Comment Form for Real-time Tools SAR (Project 2009-02)

Please **DO NOT** use this form. Please use the electronic comment form located at the link below to submit comments on the proposed Real-time Tools SAR. Comments must be submitted by **July 11, 2009**. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

http://www.nerc.com/filez/standards/Project2009-02_Real_Time_Tools.html

Background Information:
According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* dated April 2004, a principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools. In addition, the failure of control computers and alarm systems, incomplete tool sets, and the failure to supply network analysis tools with correct System data on August 14 contributed directly to this lack of situational awareness. Also, the need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations.

Recommendation 22 of the Blackout Report states "Evaluate and adopt better real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate real-time tools and their usage within the industry. The Task Force produced a report "*Real-Time Tools Survey Analysis and Recommendations*", dated March 13, 2008 that included recommendations for the functionality, performance, and management of Real-time tools.

This SAR addresses selected recommendations in the RTBPTF Report as determined by the Real-time Best Practices Standards Study Group: Project 2009-02. The SAR proposes developing requirements for the functionality, performance, and management of Real-time tools for Reliability Coordinators, Transmission Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations, with a focus on the following functionality:

> Alarming — Applications or methods that emit Real-time visible and audible signals to alert Operators to events and conditions affecting the state of the Bulk Electric System (BES).
>
> Telemetry — Applications and methods that provide status and analog values in Real-time or near-Real-time operation.
>
> Network analysis — Applications and methods to be used for determining the current state of the system and simulating the impact of 'what if' system events on the current or future state of the system.

Please review the SAR and then answer the following questions by using the electronic comment form.

1. Do you agree that either there is a reliability-related need for the proposed standards action?

   ☐ Yes
   ☐ No
   Comments:

2. Do you agree with the scope of the proposed standards action?

   ☐ Yes
   ☐ No
   Comments:

3. The SAR emphasizes functionality, performance, and management of tools as opposed to naming specific tools. The intent is to describe 'what' needs to be done as opposed to 'how' to do it. Do you agree with this approach? If not, please state specific reasons why not.

   ☐ Yes
   ☐ No
   Comments:

4. The SAR focuses on alarming, telemetry, and network analysis. Do you agree that this is the right set of functions? If not, please state specific reasons why not.

   ☐ Yes
   ☐ No
   Comments:

5. The SAR details the need for performance metrics for availability, quality, change management, maintenance coordination, and failure notification. Do you agree that this is the correct set of metrics? If not, please state specific reasons why not.

   ☐ Yes
   ☐ No
   Comments:

6. The SAR proposes to re-define Real-time. Do you agree that a new definition is needed? If not, please state specific reasons why not. If possible, specific suggested wording for a new definition would be appreciated.

   ☐ Yes
   ☐ No
   Comments:

7. The SAR includes the Generator Operator (GOP) as a possible applicable entity. Do you agree that a potential Standards Drafting Team should have the freedom to consider the GOP as an applicable entity? If not, please state specific reasons why not.

   ☐ Yes
   ☐ No
   Comments:

8. Do you believe the proposed requirements should reside in a reliability standard or should be addressed as part of the certification process?

   ☐ Reliability Standard

   ☐ Certification Process

   Comments:

9. If you are aware of the need for a regional variance or business practice that we should consider with this SAR, please identify it here.

   Regional Variance:

   Business Practice:

   Comments:

10. If you have any other comments on this SAR that you have not already provided in response to the prior questions, please provide them here.

    Comments:

Real-Time Tools Survey Analysis and Recommendations

Final Report

March 13, 2008

Prepared by the

Real-Time Tools Best Practices Task Force

TABLE OF CONTENTS

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Acronyms and Abbreviations

ACE	area control error
AEC	Alabama Electric Cooperative, Inc.
AECI	Associated Electric Cooperative, Inc.
AEP	American Electric Power
AESO	Alberta Electric System Operator
AGC	automatic generation control
AP	Allegheny Power
ATC	American Transmission Company or available transfer capability
AVR	automatic voltage regulator
BA	balancing authority
BOT	Board of Trustees (NERC)
BPAT `	Bonneville Power Administration
CFE	Comision Federal De Electricidad
CFLA	critical facility loading assessment
CIN	Cinergy Corporation
CLEC	Cleco Corporation
CMRC	California Mexico Reliability Coordinator
CSWS	AES — Central and Southwest
DCS	disturbance control standard
DEWG	Data Exchange Working Group
DMS	distribution management system
DOC	distribution operations center
DOPD	PUD #1 of Douglas County
DPL	Dayton Power and Light
DSA	dynamic stability assessment
DSM	demand-side management
DSMON	data set monitor
DTS	dispatcher training simulator
DUK	Duke Energy Corporation
ECAR	East Central Area Reliability Council
EDT	Eastern Daylight Time
EEA	energy emergency alert
EES	Entergy Services, Inc.
EMS	energy management system
EPAct	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ERCO	ERCOT ISO
ERO	electricity reliability organization
FE	FirstEnergy
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FPL	Florida Power and Light
FRCC	Florida Reliability Coordinating Council

FTC	facilitated transaction checkout
FTE	full time equivalent
GCPD	Grant County Public Utility District
GMS	geo-magnetic storm
GSU	generator step up
HMI	human-machine interface
HQT	Hydro-Quebec TransEnergie (HQT)
ICAP	Installed Capacity
ICCP	Inter-control center communications protocol
ID	identification
IDC	Interchange Distribution Calculator
IEEE	Institute of Electrical and Electronics Engineers
IMO	The Independent Electricity System Operator (IMO)
IPP	independent power producer
IROL	interconnected reliability operating limit
ISN	Inter-regional Security Network
ISO	independent system operator
ISO-NE	independent system operator New England
IT	information technology
ITC	International Transmission Company
kV	kilovolt
LES	Lincoln Electric System
LMP	locational marginal pricing
LODF	line outage distribution factor
LOOP	loss of offsite power
LTC	load top changer
MGE	Madison Gas and Electric Company
MISO	Midwest Independent System Operator
MVA	Megavoltamperes
Mvar	mega Var
MW	megawatt
NBSO	New Brunswick System Operator
NERC	North American Electric Reliability Corporation
NIPS	Northern Indiana Public Service Company
NMPC	Niagara Mohawk Power Corporation
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission
NTP	network topology processor
NWMT	NorthWestern Energy
NYIS	New York ISO
OC	Operating Committee (NERC)
OKGE	Oklahoma Gas and Electric
OPF	optimal power flow
ORS	Operating Reliability Subcommittee (NERC)
OTP	Otter Tail Power Company
PAR	phase-angle regulating

PCT	process control test
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PMU	phasor measurement unit
PNM	Public Service Company of New Mexico
PRD	production
PV	power/voltage (analysis)
QA	quality assurance
QV	reactive/voltage (analysis)
RAS	remedial action scheme
RC	reliability coordinator
RCWG	Reliability Coordinator Working Group
RDRC	Rocky Mountain — Desert Southwest Reliability Coordinator
RPU	Rochester Public Utilities
RRO	regional reliability organization
RTCAA	real-time contingency analysis availability
RTO	regional transmission organization
RTOP	regional transmission operator
RTU	remote terminal unit
RTBPTF	Real-Time Tools Best Practices Task Force
SAR	Standards Authorization Request
SC	Santee Cooper
SCADA	Supervisory Control and Data Acquisition
SCEG	South Carolina Electric and Gas Company
SEA	state estimator availability
SERC	SERC Reliability Corporation
SMD	solar magnetic disturbance
SMP	Southern Minnesota Municipal Power Agency
SOC	system operation center
SOCO	Southern Company Services, Inc.
SOL	system operating limit
SPC	Saskatchewan
SPS	Southwestern Public Service — Xcel
SPP	Southwest Power Pool
SPPC	Sierra Pacific Power Company
SPRM	City Utilities, Springfield, MO
SPS	special protection system
SRTM	study real-time maintenance
SVC	static Var compensator
SWPP	Southwest Power Pool
TAED	topology and analog error detection
TAL	City of Tallahassee
TOC	transmission operation center
TOP	transmission operator
TRS	trouble report system
TSIN	Transmission System Information Network
TT	thermal tracking

TVA	Tennessee Valley Authority
TTC	total transfer capability
TX	transformer
UFLS	under-frequency load-shed
UVLS	under-voltage load shed
VACAR	Virginia Carolinas (subregion of SERC)
var	volt ampere reactive
VEDI	Vectren Energy Delivery of Indiana
VSA	voltage stability analysis
VTWG	visualization tools working group
WAUW	Western Area Power Administration — Upper Great Plains Region
WEC	Wisconsin Energy Corporation
WPEL	Aquila, Inc.
WR	Westar

How to Read this Document

Because this document is long and full of survey findings, readers may find it helpful to start by skimming the **Table of Contents** to identify areas of particular interest and reviewing the **Executive Summary** for highlights of the main findings and recommendations. The table immediately following the Executive Summary lists of all of the report's recommendations.

Readers will find the in-depth overview presented in the **Introduction** helpful for understanding the interrelationships among the tools and practices covered in the report and the larger context for any particular topic of interest. The Introduction summarizes the history of Real-Time Tools Best Practices Task Force (RTBPTF), the task force's charge, the task force's comprehensive Real-Time Tools Survey of electric industry practices, the major findings and recommendations resulting from the analysis of the survey results, and proposals for next steps.

Readers interested in specific subjects will find it helpful, after reading the Introduction, to read the introductory sections on those subjects: **1.0, Real-Time Data Collection; 2.0, Reliability Tools for Situational Awareness; 3.0, Situational Awareness Practices; 4.0, Power System Models; 5.0, Support and Maintenance Tools**.

Following each introductory section are **specific subsections (1.1., 1.2, 1.3, 2.1, etc.)** that treat in detail the individual tools and practices investigated in this report. These sections define the tool, summarize the survey findings regarding it, and, if applicable, present recommendations related to the tool and its performance as well as noting areas for further research and analysis.

Readers interested in the details of where the industry should go next with real-time tools standards will find **Section 6.0, Next Steps** of interest.

Following the main text, **Appendices** describe the task force's survey development, participation, and analysis methodology as well as the Examples of Excellence discovered in the survey results. Aggregate survey responses are also available as pdfs at http://www.nerc.com/~filez/rtbptf.html.

Finally, a **Glossary** and an **Acronym** list are included to help readers manage the technical vocabulary of the document. The glossary will be especially useful for understanding the new technical terms and concepts the task force introduces in this report, including: "bulk electric system elements list," "critical applications monitoring," "critical equipment," "critical real-time tool," and "wide-area-view boundary."

Executive Summary

This report presents the findings and recommendations of the North American Electric Reliability Corporation (NERC) Real-Time Tools Best Practices Task Force (RTBPTF) regarding minimum acceptable capabilities and best practices for real-time tools necessary to ensure reliable electric system operation and reliability coordination.

RTBPTF's mission is primarily based on the U.S.-Canada Power System Outage Task Force findings that key causes of the August 14, 2003 northeast blackout included lack of situational awareness and inadequate reliability tools. That report also notes the need for visualization display systems to monitor system reliability.[1]

RTBPTF's recommendations result from an extensive, three-year process of fact-finding and analysis supported by the results of the Real-Time Tools Survey, the most comprehensive survey ever conducted of current electric industry practices.

Recommendations

RTBPTF makes major recommendations in three key areas to establish requirements that apply to reliability coordinators (RCs), transmission operators (TOPs), and other entities with similar responsibility:

1. Reliability Toolbox[2] — Require five real-time tools as well as performance and availability metrics and maintenance practices for each. The required tools are:

- Telemetry data systems
- Alarm tools
- Network topology processor
- State estimator
- Contingency analysis

2. Enhanced Operator Situational Awareness — Require standards and guidelines for situational awareness practices, including:

- Power-flow simulations
- Conservative operations plans
- Load-shed capability awareness
- Critical applications and facilities monitoring
- Visualization techniques

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[1] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. (Referred to in the text of this document as the *Outage Task Force Final Blackout Report*.)

[2] The relationships among the required tools are illustrated in Figure 4 of the Introduction following this Executive Summary.

The task force also recommends that NERC:

3. Address Six Major Issues to enhance the effectiveness of real-time tools:

1) Definition of the bulk electric system
2) Definition of the wide-area-view boundary
3) Development of system models and standards for exchange of model information
4) Specification of acceptable reactive reserves
5) Determination of adequate load-shed capability
6) Provision of adequate funding and staffing for maintaining and upgrading real-time tools

In addition to the major recommendations listed above, the task force makes a number of other specific recommendations related to particular real-time tools, all of which are listed in Table ES-1.

Presentation of Recommendations

The recommendations in Table ES-1 are presented throughout this report as color coded text boxes in accordance with the following color scheme:

1. Blue – Recommendations for new or revised reliability standards
2. Green – Recommendations for operating guides
3. Red – Recommendations regarding areas requiring more analysis
4. Blue-Green – Recommendations to address issues to enhance the effectiveness of real-time operation

Real-Time Tools Survey

RTBPTF's findings and recommendations are firmly grounded in the results of the Real-Time Tools Survey, a more than 300-page, web-based document with nearly 2,000 questions on a broad scope of current industry practices and plans for using real-time tools. All 17 North American RCs participated in the survey along with an additional 42 TOPs and/or Balancing Authorities (BAs) (that are not also RCs), which represent about one-third of the total number of TOPs and BAs. Thus, the survey responses reflect the current status and practices of a significant and geographically diverse portion of the North American electric industry.[3]

Focus on Situational Awareness

In this report, RTBPTF focuses on real-time tools that support system operators' situational awareness, as called for in the *Outage Task Force Final Blackout*

[3] The geographic locations of the survey participants are shown in Figure 2 (for RCs) and Figure 3 (for TOPs and BAs) of the Introduction following this Executive Summary.

Report. Situational awareness, as RTBPTF understands it, means ensuring that accurate information on current system conditions, including the likely effects of future contingencies, is continuously available in a form that allows operators to quickly grasp and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations.

Next Steps

Much work lies ahead to implement the task force's recommendations for revised standards and operating guidelines to improve reliability through better real-time operating tools and practices and to conduct needed additional analyses. In the short term, RTBPTF proposes to finish work on the following activities, which will complete the remainder of the task force's assigned scope of work:

- Append recommendations for revised standards to the existing Standards Review Forms
- Provide technical support to the standards drafting teams
- Prioritize areas requiring more analysis
- Write high-level scopes for the analysis required

Following completion of these activities, RTBPTF will disband.

RTBPTF also recommends the following additional steps, which are outside the task force's assigned scope:

- The NERC Operating Reliability Subcommittee (ORS) should determine how operating guidelines are to be developed and maintained, and

- The NERC Operating Committee (OC) should consider asking the regional reliability organizations (RROs) to develop operating guidelines as "supplements" to the NERC standards.

Organization of this Report

The core, technical portion of this report is organized into five major sections that address the main subject areas of the Real-Time Tools Survey[4] and a sixth section that details the next steps toward implementing RTBPTF's recommendations:

Section 1.0, Real-Time Data Collection
Section 2.0, Reliability Tools for Situational Awareness
Section 3.0, Situational Awareness Practices

[4] The relationships among the tools and practices covered in Sections 1-5 of this report are illustrated in Figure 1 of the Introduction that follows this Executive Summary.

Section 4.0, Power System Modeling
Section 5.0, Support and Maintenance Tools
Section 6.0, Next Steps

Within each of the five major sections, a general introduction is followed by sections focusing on the main topic areas in that section. Each topical section is structured as follows:

- Definition of the specific topic
- Background on the specific topic
- Summary of Survey Findings on the specific topic
- Task Force Recommendations on the specific topic, if any, including:
    - Recommendations for New Reliability Standards
    - Recommendations for Operating Guidelines
    - Areas Requiring More Analysis
    - Examples of Excellence

A number of appendices address the Real-Time Tools Survey development (Appendix A), participation (Appendix B) and analysis (Appendix C), as well as related web links (Appendix D). Appendix E presents the Examples of Excellence in detail. A glossary and an acronym list are also included for the reader's convenience.

Summary of Recommendations

Number	*Recommendations Related to New Reliability Standards or New Requirements to Existing Standards*	Section Number	Page Number
S1	Mandate the following reliability tools as mandatory monitoring and analysis tools.		
	Alarm Tools	2.1	12
	Telemetry Data Systems	1.1	26
	Network Topology Processor	2.3	68
	State Estimator	2.5	106
	Contingency Analysis	2.6	137
S2	Compile and maintain a list of all bulk electric system elements within RC's area of responsibility.	1.1	34
S3	Add new requirements and measures pertaining to RC monitoring of the bulk electric system.	1.1	36
S4	Develop data-exchange standards.	1.2	59
S5	Develop data-availability standards and a process for trouble resolution and escalation.	1.2	61
S6	Develop a new weather data requirement related to situational awareness and real-time operational capabilities.	1.3	69
S7	Specify and measure minimum availability for alarm tools.	2.1	13
S8	Specify and measure minimum availability for network topology processor.	2.3	69
S9	Establish a uniform formal process to determine the "wide-area view boundary" and show boundary data/results.	2.2	38
S10	Develop compliance measures for verification of the usage of "wide-area overview display" visualization tools.	2.2	44
S11	Specify and measure minimum availability for state estimator, including a requirement for solution quality.	2.5	107

Number	*Recommendations Related to New Reliability Standards or New Requirements to Existing Standards*	Section Number	Page Number
S12	Specify and measure minimum availability for contingency analysis, including a requirement for solution quality.	2.6	138
S13	Specify criteria and develop measures for defining contingencies.	2.6	143
S14	Perform one-hour-ahead power-flow simulations to assess approaching SOL and IROL violations and corresponding measures.	2.8	158
S15	Provide real-time awareness of load-shed capability to address potential or actual IROL violations.	2.13	185
S16	Require BAs to monitor contingency reserves and calculate contingency reserves at a minimum periodicity of 10 seconds.	3.1	14
S17	Revise the current-day operations requirements to delineate specific, independent requirements for monitoring operating and reactive reserves.	3.1	14
S18	Establish document plans and procedures for conservative operations.	3.3	26
S19	Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes.	3.3	26
S20	Develop formal operating guides (mitigation plans) and measures for each IROL and any SOL or other conditions having a potential impact on reliability.	3.4	37
S21	Review and update operating guides (mitigation plans) when day-ahead or current day studies indicate the potential need to implement an operating guide.	3.4	38
S22	Provide temporary operating guides (mitigation plans) with control actions for situations that could affect reliability but that have not been identified previously.	3.4	38
S23	Develop joint operating guides (mitigation plans) for situations that could require more than one RC or more than one TOP to execute actions.	3.4	39

Number	*Recommendations Related to New Reliability Standards or New Requirements to Existing Standards*	Section Number	Page Number
S24	Develop a formal procedure to document the processes for developing, reviewing, and updating operating guides (mitigation plans).	3.4	39
S25	Incorporate verifiable and traceable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates when modifying operating guides (mitigation plans).	3.4	39
S26	Write operating guides (mitigation plans) in clear, unambiguous language, leaving nothing to interpretation.	3.4	40
S27	State the specific purpose of existence for each operating guide (mitigation plan).	3.4	40
S28	Summarize the specific situation assessment and address the method of performing the assessment in each operating guide (mitigation plan).	3.4	40
S29	Identify all appropriate preventive and remedial control actions in each operating guide (mitigation plan).	3.4	41
S30	Develop criteria in operating guides (mitigation plans) to support decisions regarding whether a specific control action should be taken.	3.4	41
S31	Incorporate on-line tools that utilize on-line data when operating guides (mitigation plans) require calculations.	3.4	41
S32	Make operating guides (mitigation plans) readily available via a quick-access method such as Web-based help, EMS display notes, or on-line help systems.	3.4	42
S33	Provide the location, real-time status, and MWs of load available to be shed.	3.5	49
S34	Establish documented procedures for the reassessment and re-posturing of the system following an event.	3.6	56
S35	Provide information to operators to maintain awareness of the availability and capability of the blackstart generators and transmission restoration paths.	3.7	64

Number	***Recommendations Related to New Reliability Standards or New Requirements to Existing Standards***	**Section Number**	**Page Number**
S36	Plan and coordinate scheduled outages of blackstart generators and transmission restoration paths.	3.7	65
S37	Maintain a Critical Equipment Monitoring Document to identify tools and procedures for monitoring critical equipment.	5.2	16
S38	Maintain event logs pertaining to critical equipment status for a period of one year.	5.2	16
S39	Maintain a Critical Equipment Maintenance and Testing Document identifying tools and procedures for maintenance, modification, and testing of critical equipment.	5.2	17
S40	Monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation.	5.3	24

Number	*Recommendations Related to New Operating Guidelines*	Section Number	Page Number
G1	Identify implementation strategies and specific algorithms for conditional alarming.	2.1	14
G2	Consider human factors, ergonomics and maintenance/support issues in implementing visualization tools.	2.2	52
G3	Develop a chronological outage/return summary in network topology processor for recreating events and aiding state estimator.	2.3	73
G4	Establish state estimator solution-quality metrics to ensure accurate data and other reliability analysis.	2.5	111
G5	Identify only existing controls modeled in contingency analysis and develop conservative contingency screening criteria.	2.6	145
G6	Perform one-hour ahead contingency analysis to identify potential post-contingent problems approaching in next hour.	2.8	159
G7	Use the study real-time maintenance application to reproduce real-time snapshots.	2.9	165
G8	Develop a list of the minimum set of items that should be included in the calculations for actual and required operating reserves.	3.1	15
G9	Provide written alarm response procedures via at least one quick access method such as Web-based help or on-line help system.	3.2	20
G10	Specify the system conditions for initiating conservative operations and action plans to follow during conservative operations.	3.3	27
G11	Communicate and coordinate with neighboring systems for reassessing and re-posturing a system following an event that places the system in an insecure or unstudied state.	3.6	58

Number	***Recommendations Related to New Operating Guidelines***	**Section Number**	**Page Number**
G12	Monitor and ensure operator awareness of current conditions of blackstart generators and status of transmission restoration paths.	3.7	66
G13	Establish a change management process for performing critical equipment maintenance, modification, and testing.	5.3	27
G14	Develop a notification process when critical equipment is unavailable and an analysis/resolution process for critical equipment failures.	5.3	27
G15	Develop a critical monitoring application that interfaces to alarm tools and logs all events related to the equipment failures.	5.3	28
G16	Develop a process for monitoring critical real-time tools including change notification, status update, and severity of a situation.	5.4	35

Number	***Recommendations Related to Areas Requiring Additional Analysis***	Section Number	Page Number
A1	Investigate the impact of time skew on state-estimator solution quality.	1.2	63
A2	Identify necessary fidelity and scope of real-time models and the extent of the requisite data-exchange sets.	1.2	64
A3	Study intelligent alarm processing capability for producing a single accurate view of system status.	2.1	15
A4	Conduct research to assess current technology and practices related to the use and application of visualization tools.	2.2	53
A5	Establish a Visualization Tools Working Group (VTWG) to foster and facilitate sharing of best practices.	2.2	54
A6	Identify minimum measurement observables, adequate redundancy, and critical measurements to improve state-estimator observability and solution quality.	2.5	116
A7	Establish a pilot program to collect data and build appropriate state estimator performance metrics.	2.5	118
A8	Evaluate capability of critical facility loading assessment application in providing a backup solution if contingency analysis or the state estimator is unavailable.	2.7	150
A9	Verify accuracy of one-hour power-flow and contingency analysis results and ability to detect a potential voltage collapse revealed by a failed power-flow solution.	2.8	160
A10	Obtain additional information on how the study real-time maintenance application is utilized to enhance debugging capability.	2.9	166
A11	Assess the voltage stability assessment (VSA) application to learn how the VSA can be enhanced to become more widely used.	2.10	171
A12	Assess the dynamic stability assessment (DSA) application to learn how the DSA can be enhanced to become more widely used.	2.11	175

A13	Analyze the need to define reactive power (Mvar) capacity requirement and use a Mvar assessment application.	2.12	179
A14	Research how emergency tools and visualization techniques are used in load shedding plans.	2.13	186
A15	Analyze the need to use tools for congestion management, voltage profiles, wind-energy forecast, and weather forecast.	2.14	192
A16	Investigate processes and procedures for internal system update and external data exchange, including CIM XML models.	4.2	60
A17	Investigate whether critical application monitor tools should be independent of the critical real-time tool being monitored.	5.4	36

Number	*Recommendations Related to Major Issues to be Addressed*	Section Number	Page Number
I1	Define what constitutes bulk electric system elements and parameters as they relate to existing standards.	1.1	27
I2	Define wide-area view boundary.	2.2	38
I3	Specify acceptable reactive reserves.	3.1	13
I4	Determine adequate load-shed capability.	3.5	48
I5	Develop system models and standards for exchange of model information.	4.2	61
I6	Provide adequate funding and staffing for maintaining and upgrading real-time tools.	6.0	2

Introduction

The North American Electric Reliability Corporation (NERC) Real-Time Tools Best Practices Task Force (RTBPTF) was formed in 2004 to identify the best practices for real-time reliability tools used to build and maintain real-time network models, perform state estimation and contingency analysis, and maintain situational awareness in accordance with NERC Reliability Standards. The task force was also instructed to develop guidelines for minimally acceptable capabilities for these critical reliability tools and to recommend specific requirements to be included in reliability standards for these tools.

This report presents RTBPTF's findings and recommendations, organized by individual tool or practice under the following five major headings:

- Real-Time Data Collection
- Reliability Tools for Situational Awareness
- Situational Awareness Practices
- Modeling Practices
- Support and Maintenance Tools

In total, RTBPTF recommends:

- 40 revisions to existing NERC standards;
- 16 operating guidelines; and
- 17 areas that require more analysis

In addition, RTBPTF has assembled 24 examples of excellence in the use of real-time tools.

RTBPTF's recommendations result from an extensive, three-year process of fact-finding and analysis based on the results of the Real-Time Tools Survey, the most comprehensive survey ever conducted on current electric industry practices.

The subsections of this Introduction describe:

- the history of RTBPTF's formation
- RTBPTF's scope of work
- the Real-Time Tools Survey
- RTPBTF's major findings
- criteria by which RTBPTF's recommendations were developed
- details of RTBPTF's major recommendations
- specific proposals for next steps in NERC's work on real-time tools

Background

RTBPTF's formation and scope of work resulted from investigation of the August 14, 2003 northeast blackout by the U.S. - Canada Power System Outage Task Force and by NERC.

The passage of the Energy Policy Act of 2005 (EPAct)[1] calling for mandatory reliability standards and publication of a Federal Energy Regulatory Commission (FERC) assessment of NERC's proposed mandatory reliability standards[2] also contributed to the task force's understanding of its charge.

Blackout Investigation

The timeline leading to RTBPTF's creation begins with a December 2003 U.S.-Canada Power System Outage Task Force technical conference, which produced a series of recommendations to prevent future blackouts. Two of the conference panel discussion topics, "Operating Tools" and "Reliability Coordination," inspired the initial draft of the scope of work that was ultimately assigned to RTBPTF.

In February 2004, not long after the Outage Task Force Conference, the NERC Board of Trustees (BOT) approved the NERC Steering Group's recommended actions to prevent and mitigate future blackouts.[3] BOT directed the NERC Operating Committee (OC) to carry out Recommendation 10, which states:

> The Operating Committee shall within one year evaluate the real-time operating tools necessary for reliable operation and reliability coordination, including backup capabilities. The Operating Committee is directed to report both minimum acceptable capabilities for critical reliability functions and a guide of best practices.

The supporting discussion for Recommendation 10 states that the evaluation should include consideration of the following:

- Modeling requirements, such as model size and fidelity, real and reactive load modeling, sensitivity analyses, accuracy analyses, validation, measurement observability, update procedures, and procedures for the timely exchange of modeling data

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[1]Energy Policy Act of 2005. Public Law 109–58. 42 USC 15801.

[2] Federal Energy Regulatory Commission. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. RM06-16-000. May 11, 2006. (Referred to in the text of this document as the *FERC Staff Assessment*.)

[3] North American Electric Reliability Corporation. 2004. *August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts.* February 10. (Referred to in the text of this document as the *NERC Blackout Report*.)

- State estimation requirements, such as periodicity of execution, monitoring external facilities, solution quality, topology error and measurement error detection, failure rates including times between failures, presentation of solution results including alarms, and troubleshooting procedures
- Real-time contingency analysis requirements, such as contingency definition, periodicity of execution, monitoring external facilities, solution quality, post-contingency automatic actions, failure rates including mean/maximum times between failures, reporting of results, presentation of solution results including alarms, and troubleshooting procedures including procedures for investigating unsolvable contingencies

Next, in April 2004, the U.S.-Canada Power System Outage Task Force issued its final report.[4] Recommendation 22 of the *Outage Task Force Final Blackout Report* supports NERC's Recommendation 10. Recommendation 22 reads as follows:

> Evaluate and adopt better real-time tools for operators and reliability coordinators.
>
> NERC's requirements of February 10, 2004, direct its Operating Committee to evaluate within one year the real-time operating tools necessary for reliable operation and reliability coordination, including backup capabilities. The committee's report is to address both minimum acceptable capabilities for critical reliability functions and a guide to best practices. The [U.S.-Canada Power System Outage] Task Force supports these requirements strongly. It recommends that NERC require the committee to:
>
> A. Give particular attention in its report to the development of guidance to control areas and reliability coordinators on the use of automated wide-area situation visualization display systems and the integrity of data used in those systems.
>
> B. Prepare its report in consultation with FERC, appropriate authorities in Canada, DOE [U.S. Department of Energy], and the regional councils. The report should also inform actions by FERC and Canadian government agencies to establish minimum

[4] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. (Referred to in the text of this document as the *Outage Task Force Final Blackout Report.*)

> functional requirements for control area operators and reliability coordinators.[5]

The *Outage Task Force Final Blackout Report* makes clear the relationship between reliability tools and electric system operator situational awareness and the role of both in causing the 2003 blackout; the report also emphasizes the need for a consistent means for operators to understand the status of the power grid outside their control areas:

> A principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools and backup capabilities. In addition, the failure of First Energy's control computers and alarm system contributed directly to the lack of situational awareness. Likewise, [the Midwest Independent System Operator's] MISO's incomplete tool set and the failure to supply its state estimator with correct system data on August 14 contributed to the lack of situational awareness. The need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations….
>
> The investigation of the August 14 blackout revealed that there has been no consistent means across the Eastern Interconnection to provide an understanding of the status of the power grid outside of a control area. Improved visibility of the status of the grid beyond an operator's own area of control would aid the operator in making adjustments in its operations to mitigate potential problems. The expanded view advocated above would also enable facilities to be more proactive in operations and contingency planning.

In response to Outage Task Force Recommendation 22 and NERC Recommendation 10, OC formed RTBPTF.

Mandatory Reliability Standards

As noted above, subsequent to RTBPTF's formation, passage of EPAct and publication of the *FERC Staff Assessment* of NERC's proposed mandatory reliability standards contributed to RTBPTF's understanding of its charge.

[5] Although the task force included a member from a regional council and a liaison from FERC, the consultation with "FERC, appropriate authorities in Canada, DOE, and the regional councils" to inform the development of minimum functional requirements, as envisioned in Recommendation 22, was supplanted by RTBPTF's efforts to make specific recommendations for new reliability standards.

EPAct authorized FERC to adopt mandatory reliability rules and to certify an Electricity Reliability Organization (ERO) to enforce them. Passage of EPAct made it clear that RTBPTF's recommendations for revisions to standards, if adopted, will become enforceable mandatory requirements.

In May 2006, FERC released its preliminary *Staff Assessment* of NERC's proposed mandatory reliability standards. On the topic of analysis tools in Standard IRO-002,[6] the assessment states: "[t]he standard does not have any Compliance Measures and Levels of Noncompliance and without such specificity, the ERO will not have norms that are specific enough to implement consistent and effective enforcement." This observation makes clear the need to establish performance measures for required real-time tools and practices.

On the topic of real-time monitoring in Standard TOP-006-0,[7] FERC staff states:

> [W]hile the requirements identify the data to be gathered, they fail to describe the tools necessary to turn that data into critical reliability parameters, e.g., system capability or contingency analysis, which are required to achieve situational awareness. Reliability Coordinators, Transmission Operators, and Balancing Authorities must be aware of the status of their respective systems, and such situational awareness cannot be obtained by viewing massive amounts of raw data. The standard does not contain any Measures to assess compliance with Requirements or Levels of Non-Compliance required for enforcement.

This analysis by FERC staff underscores the need to require real-time tools that present system status information in ways that operators can quickly grasp so that they can take action to correct system problems, and the need to define performance measures for standards.

RTBPTF Scope

NERC ORS and OC approved a scope of work for RTBPTF in summer 2004.[8] RTBPTF held its first meeting in September 2004 and revised the scope to add the term "situational awareness," the task of defining "best practices," and a

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[6] "Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays."
[7] "To ensure critical reliability parameters are monitored in real-time."
[8] The initial draft of RTBPTF's scope of work had been presented for consideration at a joint meeting of the NERC ORS and the NERC Reliability Coordinator Working Group (RCWG) in January 2004 and was also submitted to the NERC Steering Group in response to their invitation for comments on their proposed *NERC Blackout Report.*

notation that there may be more than one best practice (see "Understanding RTBPTF's Scope" below.) ORS accepted the revised scope in December 2004.

RTBPTF's final scope reads as follows:

1. Define and explain what is meant by the term, "Best Practice," in the context of this work scope.
2. Develop a focused survey (preferably web-based) for distribution to entities responsible for reliable operations to determine which tools those entities use to perform state estimation, perform real-time contingency analysis, and maintain situational awareness of their systems. The survey shall be designed to identify the methods and criteria these entities employ to build and maintain the necessary models and to execute and monitor the performance of the reliability tools.
3. Develop a survey of users of automated, wide-area visualization display technologies to determine guidelines for their application and the integrity of data displayed to the users.
4. Present an interim report to the ORS summarizing the results of the surveys and outlining the scope and timeline of the remaining work.
5. Conduct detailed interviews and on-site reviews of the entities identified by the survey as having the best practices in order to document how the best practices contribute to superior performance.
6. Present a report to the ORS with recommendations for specific methods, design criteria, and performance parameters and thresholds to serve as the basis for guidelines for minimally acceptable capabilities for real-time network modeling and the use and performance of network analysis tools and situational awareness tools.
7. Provide technical support for the development of new standards for real-time network models, network analysis tools, and situational awareness tools.

In performing the assigned tasks, RTBPTF shall:

1. Consider all aspects of model building and maintenance including, but not limited to, proper model size, model fidelity, real and reactive load modeling, sensitivity analyses, accuracy analyses, validation, measurement observability, update procedures, and procedures for the timely exchange of modeling data
2. Consider all aspects of state estimation including, but not limited to, periodicity of execution, monitoring external facilities, solution quality, topology error and measurement error detection, failure rates including

mean/max times between failures, presentation of solution results including alarms, and troubleshooting procedures

3. Consider all aspects of real-time contingency analysis including, but not limited to, contingency definition, periodicity of execution, monitoring external facilities, solution quality, post-contingency automatic actions, failure rates including mean/max times between failures, reporting of results, presentation of solution results including alarms, and troubleshooting procedures including procedures for investigating unsolvable contingencies
4. Consider all elements of situational awareness in the NERC Operating Standards
5. Identify issues where best practices are nonexistent or insufficient
6. Recognize that there may be more than one "best practice" for a particular aspect of tool utilization and support
7. Consider other tools currently in use to supplement or back up state estimators or real-time contingency analysis applications
8. Address human factors engineering ("man-machine interface")
9. Investigate minimum staffing requirements to support real-time tools
10. Address real-time data acquisition, quality, and time-stamping for data used to drive real-time tools
11. Address management understanding of and commitment (funding and people) to provide appropriate tools and support
12. Identify and consider similar work that may have already been done within the Regions or sub-regions
13. Identify and consider similar work that may have already been published by EPRI [Electric Power Research Institute], IEEE [Institute of Electrical and Electronics Engineers], or other organizations
14. Take into account regional differences in preparing the interim guidelines and final recommendations.

Understanding RTBPTF's Scope

RTBPTF's understanding of its scope depends on three key concepts: the meaning of the term "best practices," the meaning of the term "situational awareness," and the relationships among real-time reliability tools and practices. The task force's considered interpretation of these three key concepts is fundamental to its approach to its work and to the structure of this report.

Best Practices

The first assignment in RTBPTF's scope is to define the term "best practice" as it applies to the task force's charge. However, the concept of best practices extends beyond RTBPTF's scope; OC created the Best Practices Task Force to define this term and identify where or how best practices apply.

The OC Best Practices Task Force final report[9] states:

> The reports following the August 14, 2003 blackout specifically referred to 'best practices,' and the U.S.-Canada Power Outage Task Force final report of April 5, 2004 suggested that the industry establish best practices in certain areas. But these reports and recommendations did not define what best practices were – they assumed the reader would infer the meaning from the context of the report or recommendation.

The Best Practices Task Force report lists specific recommendations from the blackout reports that refer to best practices and summarizes its mission by stating:

> NERC is addressing these recommendations in various reports, documents, and on-going committee tasks. But after considerable research, the task force found there was no single definition of best practices. We also hear the term best practices in reports and committee discussions now and then to describe procedures that, while not standards, are generally accepted as "good things to do," and that work well. However, NERC has never attempted to either define best practices or suggest where or how they could be used. Are best practices in some unique way better than guidelines or examples of excellence? Or do people refer to best practices in the more general sense of "these are good things to do," or "these are ways to achieve excellence?"

The OC's Best Practices Task Force conclusions can be paraphrased as follows[10]:

- NERC has adopted a comprehensive set of mandatory reliability standards, and the Best Practices Task Force believes that adding a comprehensive collection of voluntary practices that represent the years of wisdom and achievements in interconnected systems operation would be a worthwhile goal.

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[9] *Best Practices Task Force Report: Discussions, Conclusions, and Recommendations*. 2005. December 1.

[10] These conclusions are paraphrased from the *Best Practices Task Force Report: Discussions, Conclusions, and Recommendations.* 2005. December 1.

These practices (aptly termed as “good things to do”) would complement existing NERC mandatory reliability standards.

- The Best Practices Task Force believes that there are several existing sources within NERC that can be drawn upon to serve the purpose stated above. These include Examples of Excellence, former NERC Operating Guides, Regional Guides, and surveys of operating practices (e. g., RTBPTF Survey).
- The Best Practices Task Force sees no need to develop a separate set of documents called best practices because that term does not have a uniform definition in our industry; it means different things to different people. Operating Guidelines, as well as NERC’s Examples of Excellence, will provide two different kinds of resources for promoting operations excellence. Both are developed by industry experts for industry experts, relate well to the standards, can provide meaningful recommendations for promoting excellence in systems operation, and are voluntary. The key difference between examples of excellence and operating guidelines is that the former are unique to individual organizations and may not apply to the wide interests of the industry, while the latter are more applicable across the industry. Both are valuable, but are not substitutes for one another.

RTBPTF adopted the Best Practices Task Force recommendations and organized RTBPTF deliverables accordingly. Thus, the reader will see in this report, where applicable, recommendations for operating guidelines and descriptions of examples of excellence. (Examples of excellence are listed briefly in the applicable sections of the report and described in more detail in Appendix E).

Situational Awareness

Because lack of situational awareness was determined to be central to causes of the 2003 blackout and because this term clearly expresses the purpose of using real-time reliability tools, RTBPTF explicitly added “situational awareness” to its scope.

RTBPTF defines “situational awareness” as ensuring that accurate information on current system conditions is continuously available to operators. This includes information on the current state of bulk electric system elements as well as on the potential impact of contingencies that might affect these elements. This information must be accurate, dependable, timely, and comprehensive enough for operators to rapidly and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations.

Relationships Among Real-Time Tools and Practices

The real-time reliability tools that are the core subject of this report[11] are fundamental to operators' situational awareness and ability to take prompt, effective corrective action. However, the quality of information supplied by these tools depends on the quality of telemetry and other real-time data as well as on situational awareness practices, system modeling practices, and tool maintenance and availability. The task force's understanding that all these elements are necessary for operator situational awareness was central to its decision to address the following tools and practices:

Real-Time Data Collection — Collecting raw real-time data is the first step in the complex process of producing the accurate, dependable, readily understood information that operators need to maintain situational awareness. Real-time models must be updated with the current status of all modeled elements and the current values of power flows and voltages so that tools such as the network topology processor and state estimator can convert these data into the accurate and dependable information operators need to maintain situational awareness. Thus, RTBPTF included real-time data collection in its scope.

Situational Awareness Practices – Information from real-time reliability tools is only meaningful if operators know how to act on it – that is, how to modify operational strategy in response to real or potential degradation in the reliability of the portion of the bulk electric system for which they are responsible. In some situations, documented procedures ("situational awareness practices") must be established to ensure that operators know the possible or required actions to take. Because it is essential that the information provided by real-time reliability tools allows operators to act to maintain system reliability, RTBPTF included situational awareness practices in its scope.

Modeling Practices — Real-time tools, such as the state estimator and contingency analysis, require a real-time mathematical model of some portion of the bulk electric system in order to function. The size, scope, and content of the required model are functions of the size, location, and scope of responsibility of the entity using the real-time tools. Even the best-designed, advanced tools can be severely compromised by inaccuracies and omissions in the network models upon which they rely. The value of the information provided to operators by real-

[11] RTBPTF focuses only on real-time tools to aid system operators' situational awareness, as called for by the NERC and Outage Task Force reports on the investigation of the 2003 blackout. Thus, RTBPTF's investigation did not include long-term, medium-term, day-ahead, or training tools although the task force recognizes that these tools may be essential for carrying out entities' other reliability-related responsibilities. Similarly, RTBPTF did not consider real-time tools related to market or economic operations.

time reliability tools thus depends heavily on the practices used to build and maintain the requisite models. Therefore, RTBPTF included modeling practices in its scope.

Support and Maintenance Tools – Operators need to be aware of the status of their real-time tools. If a computer problem, data-link failure, or other circumstance interferes with the function of a real-time tool, the operators who rely upon that tool need to be informed so that they will not unknowingly rely on outdated or incorrect information and can take appropriate backup steps. Therefore, RTBPTF included operator awareness of the availability of real-time tools in its scope.

Figure 1 illustrates the interrelationships of the five major topics addressed in this report. Each category represented in Figure 1 is a major section heading in both the Real-Time Tools Survey and this report, as explained in more detail in the sections on the survey, task force recommendations, and report organization below. The RTBPTF adopted an inclusive perspective by explicitly addressing supporting applications, practices, and processes related to real-time tools.

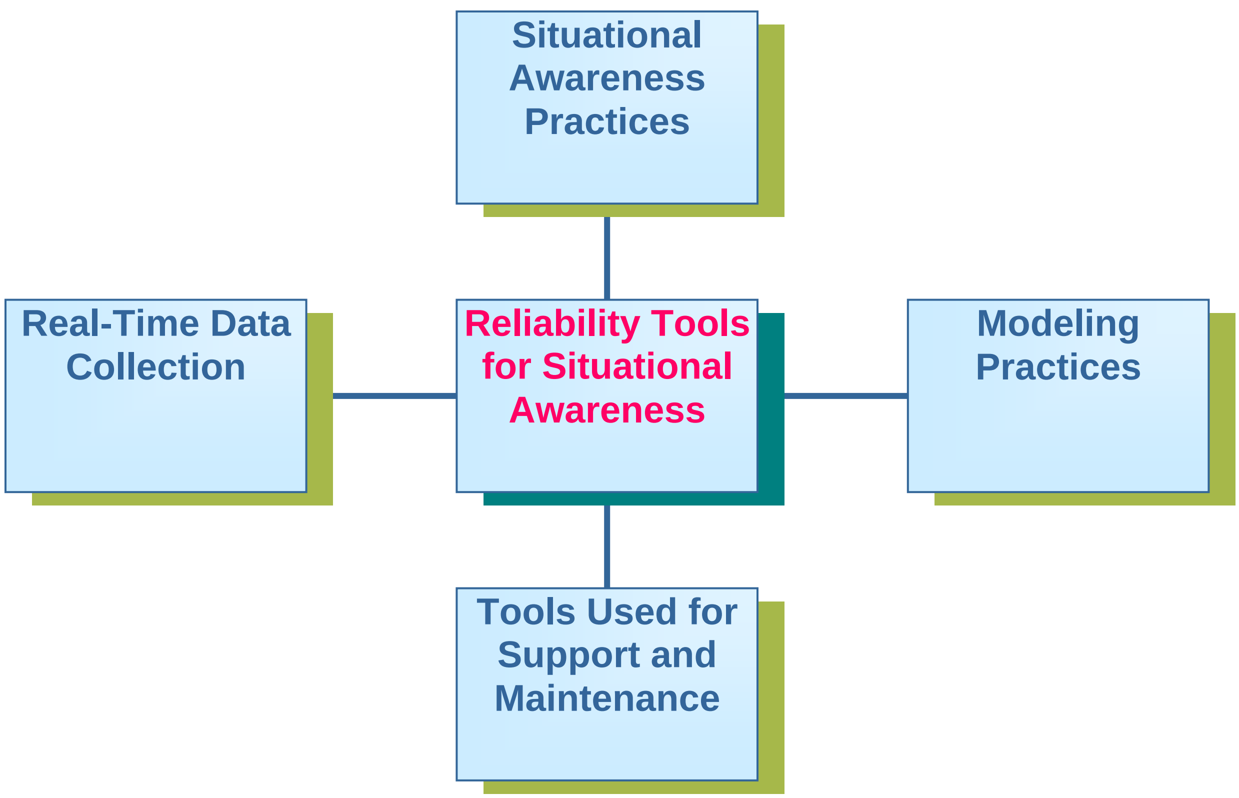

Figure 1. Real-Time Tools and Supporting Practices and Processes.

Survey Approach and Analysis

RTBPTF's principal activity was the development, administration, and analysis of the Real-Time Tools Survey. From fall 2004 through spring 2005, RTBPTF developed the survey, which gathered detailed information on the topics below. For more information on the survey's development, please see Appendix A.

Real-Time Data Collection

This section of the survey addresses the following real-time data, which are needed as input for real-time reliability applications:

- Telemetry data
- Inter-control center communications protocol (ICCP)-specific data
- Miscellaneous data

The questions in this section of the survey focus on the types of telemetry and other near-real-time data that respondents use in Supervisory Control and Data Acquisition/Energy Management System (SCADA/EMS) and network and other applications to monitor the bulk electric system. The data addressed in this section could come from SCADA, ICCP (or other forms of inter-utility data links), Inter-regional security network (ISN), or other systems communicating in continuous real- or near-real-time operation.

Modeling Practices

This section of the survey addresses two topics related to real-time network models:

- Model characteristics
- Modeling practices and tools

The questions in this section of the survey focus on several issues, including, but not limited to: model size, model fidelity, real and reactive load modeling, sensitivity analysis, accuracy analysis, validation, measurement observability, and update and data exchange procedures.

Reliability Tools for Situational Awareness

This section of the survey covers tools used to ensure reliable operations and maintain situational awareness, including:

- Alarm tools
- Visualization tools
- Network topology processor
- Topology & analog error detection
- State estimator
- Contingency analysis
- Critical facility loading assessment (CFLA)

- Power flow
- Study real-time maintenance (SRTM)
- Voltage stability assessment
- Dynamic stability assessment
- Capacity assessment application
- Emergency tools
- Other current, operational tools
- Other future tools

Situational Awareness Practices

This section of the survey addresses operating practices, processes, and procedures that support or maintain situational awareness in the following areas:

- Reserve monitoring
- Alarm response
- Conservative operations
- Operating guides (mitigation plans)
- Load-shed capability awareness
- System reassessment and reposturing
- Blackstart capability awareness

The questions in this section of the survey focus on eliciting information about practices to ensure that operators a) have the information they need to be aware of potentially unreliable system conditions and b) know what actions they can take to maintain reliability.

Support and Maintenance Tools

This section of the survey addresses support tools and practices that are essential to ensuring the integrity and availability of real-time reliability tools, including:

- Display maintenance tool
- Change management tools & practices
- Facilities monitoring
- Critical applications monitoring
- Trouble reporting tool

Survey Participation

The survey was administered in summer and fall of 2005 through a secure, web-based server hosted by NERC in Princeton NJ.[12] RTBPTF invited survey

[12] Lawrence Berkeley National Laboratory developed the software implementation and web interface for the survey and created a database and software tools to aid RTBPTF in analyzing survey results. NERC and RTBPTF members gratefully acknowledge the support of Lawrence Berkeley National Laboratory of the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability for these activities.

responses from all registered reliability coordinators (RCs), transmission operators (TOPs), balancing authorities (BAs), and any other entity using real-time tools.

The response to the survey was excellent, especially in view of its length and the considerable effort required completing it. As shown in Figure 2, all 17 North American RCs participated in the survey. Figure 3 shows the additional 42 TOPs and/or BAs (that are not also RCs) that participated. This level of participation means that the survey responses provide a comprehensive snapshot of the current practices of a significant and geographically diverse portion of the North American electric industry. For more information on survey participation, please see Appendix B.

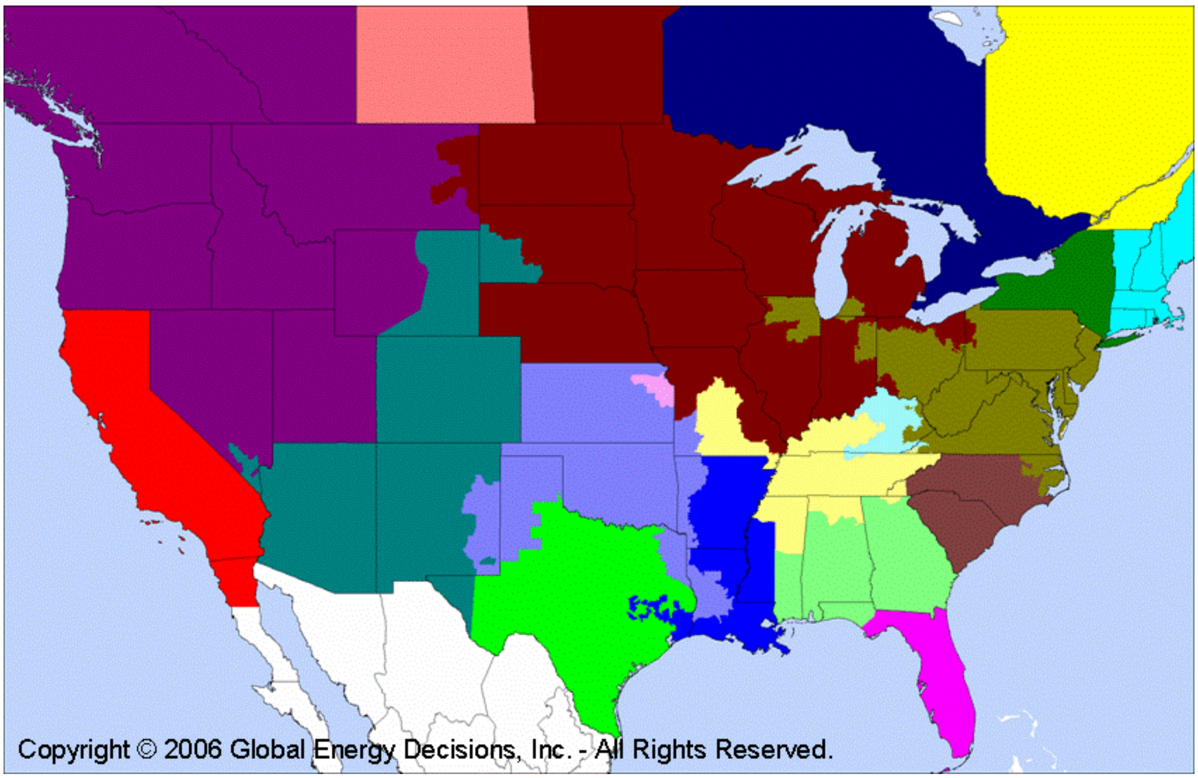

Figure 1 – Footprint of RCs that participated in the Real-Time Tools Survey

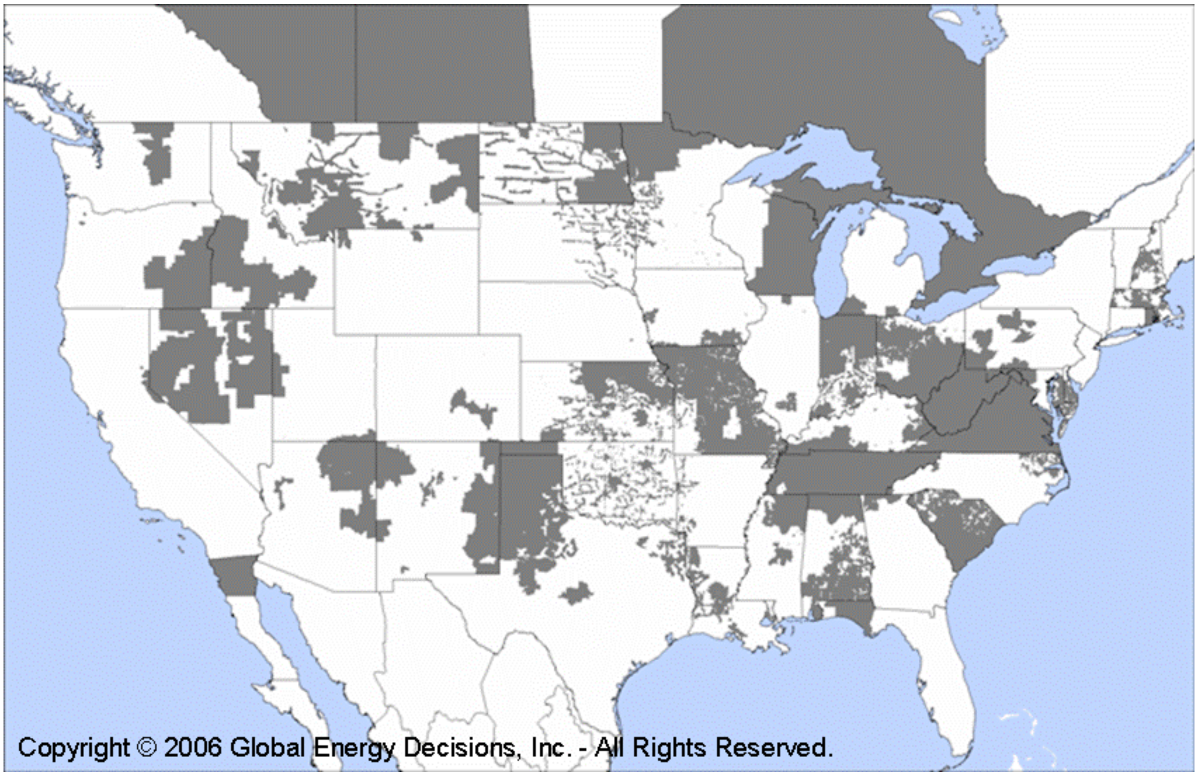

Figure 2 – Footprint of TOPs and BAs (that are not also RCs) that participated in the Real-Time Tools Survey

Survey Analysis

RTBPTF analyzed the survey responses in 2006. First, the task force distilled initial findings by topic and reviewed these findings in relation to the *Outage Task Force Final Blackout Report*, *NERC Blackout Report*, and other relevant background material. The task force focused on issues directly related to reliability, i.e., findings related to tools and situational awareness issues that had been identified as causes of the blackout. RTBPTF identified patterns of similar responses that indicated prevailing industry practices and then reviewed existing reliability standards to see how these tools and issues were addressed. Finally, the task force identified major issues that needed to be resolved. For more information on the survey analysis methodology, please see Appendix C.

The task force's findings are summarized in the next section below.

Overview of Findings

Based on its analysis of the Real-Time Tools Survey results, the task force made a large number of findings. The key findings for each major section of the report are summarized below with reference to the task force's relevant major recommendations, which are presented in more detail in the Recommendations section later in this introduction.

Real-Time Data Collection

RTBPTF finds that adequate, timely, accurate telemetry data on the current status of bulk electric system elements are essential for situational awareness. Bulk electric system elements that have the potential to impact system operations by causing a system operating limit (SOL) or interconnected reliability operating limit (IROL) violation and that are within an entity's footprint or adjacent to it should be telemetered. Accordingly, telemetry data systems are among RTBPTF's five recommended mandatory real-time tools, as described in the Recommendations section below. RTBPTF also recommends that NERC and the industry clarify the definition of bulk electric system elements and the wide-area-view boundary for telemetry data, consistent with this impact-based definition.

RTBPTF's analysis of the survey findings related to real-time data collection and all of the task force's recommendations on this topic are found in the following sections of this report: Section 1.0, Real-Time Data Collection; Section 1.1, Telemetry Data; Section 1.2, ICCP-Specific Data; and Section 1.3, Miscellaneous Data.

Reliability Tools for Situational Awareness

RTBPTF concludes that situational awareness requires, at a minimum:

- Functioning alarms that notify operators of current or potential violations of limits

- Timely and accurate network topology processing and state estimation to ensure that alarms can be reliably processed (when appropriate) and that meaningful contingency analysis can be performed

- Timely and accurate contingency analysis to identify potential SOL or IROL violations

Accordingly, alarm, network topology processing, state estimation, and contingency analysis tools are included in RTBPTF's five recommended mandatory real-time tools. Additional real-time tools and processes for power flow, load-shed capability, and visualization techniques are included as part of other RTBPTF recommendations.

RTBPTF's analysis of the survey findings related to real-time tools for situational awareness and all of the task force's recommendations on this topic are found in the following sections of this report: Section 2.0, Reliability Tools for Situational Awareness; Section 2.1, Alarm Tools; Section 2.2, Visualization Techniques; Section 2.3, Network Topology Processor; Section 2.4, Topology and Analog Error Detection; Section 2.5, State Estimator; Section 2.6, Contingency Analysis;

Section 2.7, Critical Facility Loading Assessment; Section 2.8, Power Flow; Section 2.9, Study Real-Time Maintenance; Section 2.10, Voltage Stability Assessment; Section 2.11, Dynamic Stability Assessment; Section 2.12, Capacity Assessment; Section 2.13, Emergency Tools; Section 2.14, Other Tools (Current and Operational). [An additional section, Section 2.15 Other Tools (Future), was planned but is omitted from this report because the survey responses yielded insufficient information on this topic.]

Situational Awareness Practices

The task force concludes that documented conservative operations practices are a key element of situational awareness practices and thus includes conservative operations plans in its recommendations. The task force also recommends, in its list of major issues that should be addressed to enhance the effectiveness of real-time tools, that NERC and the industry specify what constitutes acceptable reactive reserves and load-shed capability.

RTBPTF's analysis of the survey findings related to situational awareness practices and all of the task force's recommendations on this topic are found in the following sections of this report: Section 3.0, Situational Awareness Practices; Section 3.1, Reserve Monitoring; Section 3.2, Alarm Response Procedures; Section 3.3, Conservative Operations; Section 3.4, Operating Guides; Section 3.5, Load-Shed Capability; Section 3.6, System Reassessment and Re-posturing; Section 3.7, Black-Start Capability.

Power System Modeling

Although defining the elements represented in internal network models is relatively straightforward, the task force finds that defining the elements to be represented in external models is much more complex. External models must be appropriately sized and adequately updated and maintained to ensure that they can accurately represent pre- and post-contingency conditions. RTBPTF recommends that NERC and the industry develop criteria, guidelines, and standards for internal and, especially, external system models as well as data exchange. As with telemetry data, RTBPTF recommends defining what constitute bulk electric system elements and the wide-area view based on the potential impacts of these elements on an entity's ability to operate reliably; these definitions should form the basis for model development and data exchange standards.

RTBPTF's analysis of the survey findings related to power system modeling and all of the task force's recommendations on this topic are found in the following sections of this report: Section 4.0, Power System Models; Section 4.1, Model Characteristics; Section 4.2, Modeling Practices and Tools.

Support and Maintenance Tools

RTBPTF finds that RC and TOP control centers use a variety of applications and practices to monitor the status of real-time tools and supporting computer systems and communications networks. Thus, RTBPTF's recommendations include requirements for critical applications and facilities monitoring tools.

RTBPTF's analysis of the survey findings related to support and maintenance tools and all of the task force's recommendations on this topic are found in the following sections of this report: Section 5.0, Support and Maintenance Tools; Section 5.1, Display Maintenance Tool; Section 5.2, Change Management Tools and Practices; Section 5.3, Facilities Monitoring; Section 5.4, Critical Applications Monitoring; Section 5.5, Trouble Reporting Tool.

Criteria for Developing Recommendations

RTBPTF formulated its recommendations for real-time tools based on its survey analysis and on the following five key criteria, which the task force developed based on its assigned scope and the results of the 2003 blackout investigation:

1. Support NERC Reliability and Market Interface Principles.[13]

2. Address current needs and known gaps, such as those identified in the August 14, 2003 blackout reports by NERC and the Outage Task Force and in the *FERC Staff Assessment*. (RTBPTF also considered recommendations made by FERC Consultant Frank Macedo in his presentation, "Reliability Software: Minimum Recommendations and Best Practices," at the July 14, 2004 FERC technical conference.)[14]

3. Represent effective and feasible practices that are prevalent in the industry today. That is, the recommendations must be supported by the survey findings.

4. Identify performance requirements for which compliance can be assessed unambiguously and, to the extent defensible based on survey findings, through the use of quantitative metrics.

5. Represent the consensus of active RTBPTF members.

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[13] ftp://ftp.nerc.com/pub/sys/all_updl/tsc/stf/ReliabilityandMarketInterfacePrinciples.pdf
[14] Macedo, Frank, Consultant to FERC. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14.
http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

Recommendations

RTBPTF's major recommendations are summarized below. A summary list of all the recommendations in this report is presented in Table ES-1. The details of each recommendation appear in the relevant subsection of the report.

RTBPTF makes major recommendations in three key areas. The first two recommendations summarized below apply to RCs, TOPs, and other entities with similar responsibility:

1. Reliability Toolbox – Require five real-time tools as well as performance and availability metrics and maintenance practices for each. The required tools are:

- Telemetry data systems
- Alarm tools
- Network topology processor
- State estimator
- Contingency analysis

2. Enhanced Operator Situational Awareness – Require standards and guidelines for situational awareness practices, including:

- Power-flow simulations
- Conservative operations plans
- Load-shed capability awareness
- Critical applications and facilities monitoring
- Visualization techniques

The task force also recommends that NERC:

3. Address Six Major Issues to enhance the effectiveness of real-time tools:

1) Definition of the bulk electric system
2) Definition of the wide-area-view boundary
3) Development of system models and standards for exchange of model information
4) Specification of acceptable reactive reserves
5) Determination of adequate load-shed capability
6) Provision of adequate funding and staffing for maintaining and upgrading real-time tools

Each of these recommendations is described in more detail below.

Require the Use of Five Real-Time Tools

RTBPTF recommends that, to ensure reliability monitoring of the bulk electric system and maintenance of situational awareness, five real-time tools become mandatory with quantitative measures for minimum acceptable levels of performance for both RCs and TOPs (as a revision to TOP-006).[15] These required tools should be viewed as the core elements of an operator's "reliability toolbox." Figure 4 illustrates the relationships among these tools (and supporting applications).

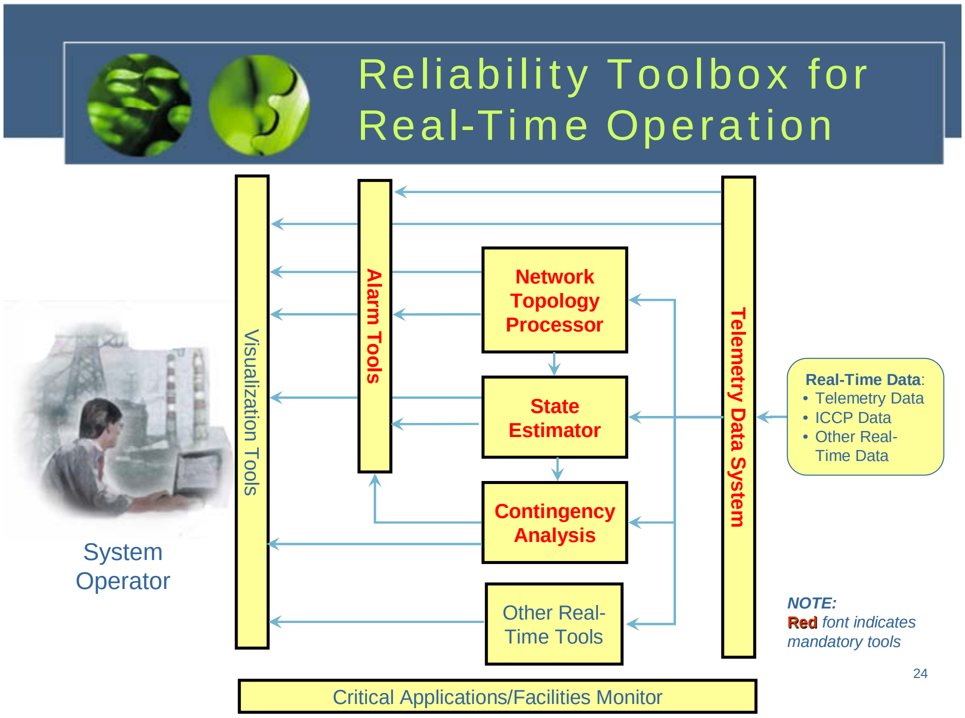

Figure 4 – Reliability Toolbox

RTBPTF recommends that the use of these five real-time tools be mandatory for all RCs and TOPs. RTBPTF further recommends that these requirements apply to any entity that has been delegated responsibility, by an RC or TOP, to operate these tools, regardless of the entity's registered designation. "Delegated responsibility to operate these tools" means the entity uses any of these tools to support or complement the RC's or TOP's ability to operate the bulk electric system reliably in accordance with formal agreements, contracts, or previously established practices or procedures.

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15 RTBPTF recognizes that differences will arise naturally between TOPs and RCs in the use of these tools. For example, the definition of the wide-area boundary (for RCs) and the "local" transmission system (for TOPs) will have implications for the scope of the network model that each relies upon.

Mandatory Tool #1: Telemetry Data Systems – Telemetry data systems update status and analog values from SCADA/EMS (via ICCP, ISN, etc.) continuously in real time or near-real time. These systems are the primary direct and indirect sources of situational awareness for operators (they function as indirect sources when they support other applications).

RTBPTF recommends modifying existing standards to require telemetry data system use. The task force also makes four supporting recommendations for telemetry data systems:

1) Increase the minimum update frequency for operational reliability data from once every 10 minutes to once every 10 seconds.[16]

2) Standardize the procedures, processes, and rules governing key data exchange issues.[17]

3) Institute a requirement for data availability from ICCP or other equivalent systems, based on the ratio of "good" data received (as defined by data quality codes) to total data received. The ratio must exceed 99 percent for 99 percent of the sampled periods during a calendar month. In addition, the ratio must not be less than 99 percent for any 30 consecutive minutes.

4) Establish minimum response times for restoration of data exchange between control centers following the loss of a data link or other problems within the source system. As part of this requirement, a trouble-resolution process standard must be developed that requires all entities responsible for management and maintenance of ICCP or equivalent systems to identify, with data recipients that could be affected by a loss of data exchange capability, a mutually agreeable restoration target time. The standard process must also include service-restoration escalation procedures and prioritization criteria.

RTBPTF recognizes that the many parties involved in monitoring, transmitting, and receiving data share the responsibility for maintaining the availability of high-quality data. Assignment of specific responsibilities for sub-par performance is not within RTBPTF's scope but should be considered as part of the standards development process.

[16] Section 1.1, Telemetry Data, contains a complete list of data elements to which the recommended update frequency should be applied.

[17] These issues include: interoperability of ICCP and equivalent systems, data access restrictions, data-naming conventions, change management and coordination, joint testing and data checkout, quality codes, and dispute resolution.

Mandatory Tool #2: Alarm Tools – Alarm tools give real-time visual and audible signals to alert operators and others about events affecting the state of the bulk electric system. Alarms may be initiated by information transmitted directly from telemetry data systems or other applications, such as the state estimator and contingency analysis. Alarms are essential for ensuring operator situational awareness.

RTBPTF recommends modifying existing standards to require use of alarm tools. RTBPTF also recommends mandatory processes to help ensure that alarm tools are always available. RTBPTF supports filtering, prioritizing, and grouping alarms as an important feature common to most alarm tools. However, the task force does not recommend making additional intelligent alarm-processing capabilities mandatory at this time because survey results show that adoption of these capabilities is not yet widespread in the industry.

Mandatory Tool #3: Network Topology Processor – A network topology processor can be used in more than one way: to support visualization tools in identifying electrical islands or isolated or open-ended equipment, and to convert a nodal network model, based on SCADA breaker and switch statuses, into a bus-branch model for use by other network applications. Use of this tool for the latter purpose is essential because two applications that are mandatory for situational awareness, the state estimator and contingency analysis, cannot be run without this conversion.

RTBPTF recommends modifying existing standards to require use of a network topology processor.[18] RTBPTF also recommends specific availability requirements, which depend on the functions supported by the tool.

Mandatory Tool #4: State Estimator – A state estimator performs statistical analysis using imperfect, redundant telemetered data from the power system and a power system model to assess the system's current condition. State estimator output is the primary input for all network analysis applications, such as contingency analysis and power flow, and can also be used to generate alarms for overloads or voltage problems on branches and buses. If the state estimator is not working or is working incorrectly, real-time network analysis, such as contingency analysis, either cannot be performed or will not produce valid results. Situational awareness depends on valid contingency analysis results.

RTBPTF recommends modifying existing standards to require use of a state estimator. RTBPTF also recommends specifying minimum requirements for the availability of valid, useful state estimator results based on two metrics:

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[18] This and the following RTBPTF recommendations for two additional mandatory real-time tools should be viewed jointly. For example, RTBPTF recognizes that a network topology processor is sometimes maintained as an integrated process within a state estimator.

1) The state estimator must have at least one converged solution (i.e., a state-estimated solution) for at least 97.5 percent of clock 10-minute periods (six non-overlapping periods per hour) during a calendar month, and

2) The state estimator must have at least one converged solution (i.e., a state-estimated solution) for every continuous 30-minute interval during a calendar day.[19]

The quality of state estimator solutions needs to be formally addressed, but RTBPTF concludes that more analysis is required to formulate and specify technically defensible solution-quality metrics and performance requirements. RTBPTF maintains that specification of a single performance metric and target would be inappropriate at this time. Other, corollary issues must be considered, such as whether external model specification is adequate and whether the telemetry data upon which the state estimator depends are valid. Until these issues are addressed, focus on a specific performance metric and target will lead to a false sense of security regarding the quality of state estimator solutions. Thus, at this time, RTBPTF recommends the development of operating guidelines for solution-quality metrics and a parallel process of tracking and analyzing state estimator performance.[20]

Mandatory Tool #5: Contingency Analysis – A contingency analysis tool simulates power flow for a set of contingencies and calculates the post-contingency thermal loading on and/or voltages at a set of monitored facilities. The results from contingency analysis identify potential SOL and IROL violations. These results, in turn, inform alarm tools (including visualization tools) and may initiate other applications.

RTBPTF recommends modifying existing standards to require contingency analysis. RTBPTF also recommends specifying minimum acceptable availability and use of contingency analysis, the definition of contingencies with respect to relay actions, and procedures for addressing failed contingency analysis:

1) Contingency analysis must be run in conjunction with a converged state estimator solution for at least 97.5 percent of clock one-minute periods (six non-overlapping periods per hour) during a calendar month.

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[19] These timing requirements are consistent with NERC's mandate to MISO to fully implement and test its state estimator and contingency analysis tools "to ensure that they can operate reliably no less than every 10 minutes" (see the *NERC Blackout Report*). These requirements are also consistent with the requirement that operators must be aware of IROL and SOL violations and be able to take action to address them within no more than 30 minutes.

[20] Examples of solution-quality metrics that should be considered include: trend of cost index (sometimes called a "performance index"), trend of number of anomalous measurements, ranked normalized residuals of individual measurements, maximum MW and Mvar mismatch, trend of number of iterations, and major topology changes.

2) Contingency analysis must be run at least once for every continuous 30-minute interval during a calendar day.[21]

3) Real-time contingencies must be defined so that they accurately reproduce the results of the actions of protective relays, which remove elements from service to minimize damage or stop the spread of undesirable system conditions.[22]

4) The total number of “unsolved” contingencies (i.e., contingencies for which the power flow fails to converge and therefore does not produce a solution) must be recorded, at a minimum, every 30 minutes. The actions taken to resolve unsolved contingencies and procedures to investigate and resolve unsolved contingencies must be documented.

Because the Reliability Toolbox is an overarching recommendation that draws on findings from many sections of this report, the rationale for this recommendation and the recommended wording for the revisions to standard TOP-006 appear, in the same format as used for the other recommendations throughout this report, in a separate section, Reliability Toolbox Recommendation and Rationale, following this introduction.

Require Supporting Tools and Practices

RTBPTF makes several major recommendations regarding tools and practices that support the five mandatory real-time tools in the Reliability Toolbox:

Power Flow – The power-flow application calculates the state of the power system (flows, voltages, and angles) using available input data for load, generation, net interchange, and facility status. On-line power flow is widely used to assess system conditions or perform look-ahead analysis. It is also used in “n-1” contingency analysis and to identify potential future voltage collapse or reliability problems.

[21] The justifications for these two performance metrics and minimum acceptable performance targets are the same as those described previously for the state estimator.

[22] This recommendation is intended to clarify the current reliability standard to ensure that the list of contingencies includes all bulk electric system elements that, when out of service, can cause an SOL or IROL violation or overload on any other facility. In other words, although NERC standard FAC-010 considers only individual bulk electric system elements, RTBPTF recommends that the definition of a single contingency, for the purpose of this recommendation, include explicit consideration of network topology. This is to ensure that single events that result in the simultaneous outage of multiple bulk electric system elements are analyzed.

RTBPTF recommends revising existing standards to require RCs and TOPs to perform one-hour-ahead power-flow simulations following critical system events, extreme load conditions, large power transactions, and major planned outages.

Conservative Operations – Conservative operations refer to intentional, proactive practices in response to unknown, insecure, or potentially risky system conditions. Conservative operations are intended to move the system to a known, secure, and low-risk operating posture. For example, the power system is postured differently for different impending conditions, such as hurricanes, ice storms, cold fronts, etc.

RTBPTF recommends revisions to and coordination among several existing reliability standards to require that each RC and TOP have documented conservative operations plans and procedures. These plans and procedures must identify credible conditions that could lead to an unknown, insecure, or potentially risky operating state and the appropriate actions that operators are expected to take in response.

Awareness of Load-Shed Capability – Load-shed capability awareness is current knowledge of the status, availability, magnitude, and time-to-deploy of all customer load that can be dropped on an emergency basis. Without this knowledge, RCs and TOPs cannot ensure that they can successfully perform this control action of last resort; this knowledge is an essential element of situational awareness.

RTBPTF recommends modifying existing standards to require operator awareness of actual load-shed capability in real time. However, RTBPTF recognizes that procedures for determining the amount, location, and maximum time-to-deploy of load-shed resources must be clarified. This topic is addressed separately below as one of the six major issues RTBPTF recommends that NERC and the industry address to enhance the effectiveness of real-time tools.

Critical Applications and Facilities Monitoring – Critical applications and facilities monitoring tracks the status and availability of real-time tools, including, but not limited to, the five recommended mandatory tools described above. As noted earlier, RTBPTF recommends measurable indices of performance (metrics) and minimum performance requirements based on these indices for each of the five mandatory tools, to ensure that the data produced by those tools are meaningful. However, critical applications and facilities monitoring is also needed to ensure that the information provided by these tools is current and continuously available to operators and technical support staff.

RTBPTF recommends requirements for a separate process (or support tool) that continuously monitors the availability and status of the five mandatory reliability tools as well as other critical tools.[23] RTBPTF also recommends mandatory reporting requirements for event logs and maintenance documentation.

Visualization Techniques **–** Visualization techniques are a group of user-interface applications, tools, and displays that provide concise visual monitoring and enhanced multiple views of relevant power system data in real time to operators and others.

RTBPTF recommends modifying existing IRO and TOP reliability standards to require the use of visualization tools as part of the measures for compliance with existing NERC reliability standards. RTBPTF also endorses ongoing efforts to research and develop visualization techniques consistent with Recommendation 13 of the *Outage Task Force Final Blackout Report.*

RTBPTF also recommends that NERC:

1) Establish a Visualization Tools Working Group (VTWG) to foster and facilitate sharing of industry best practices for use of visualization tools. This working group could continue to recommend and develop standards and operating guidelines for best methods and practices for presenting information to operators.

2) Establish industry and technical forums, involving academic, research, and other organizations, that focus on visualization tools.

Address Six Issues to Enhance the Effectiveness of Real-Time Tools

RTBPTF's above recommendations stand on their own, and NERC and the industry should implement these recommendations as soon as practicable. In addition, RTBPTF has identified six issues that are closely related to its recommendations and that NERC and the industry should address to enhance the effectiveness of real-time tools.

Issue #1: Bulk Electric System Elements Should be Defined. The effectiveness of several of RTBPTF's recommendations depends on the adequacy of telemetry, modeling, and exchange of appropriate data regarding bulk electric system elements. RTBPTF recommends that NERC and regional reliability organizations (RROs) define criteria for what constitute bulk electric system elements and that

[23] RTBPTF notes that NERC cyber-security standards address the availability of critical tools. However, cyber-security standards do not address operator situational awareness. Cyber-security standards focus primarily on protecting and securing critical cyber assets (e.g., CIP-007) and do not adequately acknowledge or address operators' needs for these tools to monitor the bulk electric system and maintain situational awareness.

RCs create and maintain a comprehensive, consistent list of all bulk electric system elements within their respective footprints.

In support of actions by others to define bulk electric system elements and based on RTBPTF's system-operations perspective, the task force recommends basing the definition of bulk electric system elements on a clear, unambiguous NERC and regionally approved impact-based methodology. Application of this method should lead to a definition of bulk electric system elements that refers only to electrical facilities that, if out of service, could lead to an SOL or IROL violation. RTBPTF does not support a definition of bulk electric system elements that is based on electrical characteristics. RTBPTF formulated all of its recommendations from this perspective.[24] The task force notes this perspective both to inform ongoing industry discussions and to provide a context for its own recommendations.

Issue #2: The Wide-Area Boundary Should be Defined. Standard IRO-003's Purpose Statement says that "[t]he Reliability Coordinator must have a wide area view of its own Reliability Coordinator Area and that of neighboring Reliability Coordinators." The NERC glossary defines "wide area" as "[t]he entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits."

RTBPTF defines "wide-area view" as the monitoring boundary for RCs. Several of RTBPTF's recommendations depend on appropriate definition of and exchange of information about bulk electric system elements. For RCs, the identification of their "wide area" of responsibility depends on the definition of bulk electric system elements.

In this report, RTBPTF introduces the concept of a "wide-area-view boundary," defined as the network model boundary for the "wide area" as defined by NERC. For reliability coordinators, the wide-area-view boundary defines the minimum required network model needed to support the monitoring requirements for the wide area. This network model should contain all the bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) encompassed by the wide-area-view boundary. Sections 4.1, Model Characteristics, and 4.2, Modeling Practices and Tools, of this report discuss the wide-area-view boundary in more detail.

The wide area that a reliability coordinator must monitor must include the bulk electric system elements in adjacent reliability coordinator footprints that individually (if they were out of service) could impact calculations of SOLs or IROLs beyond a yet-to-be-defined threshold. The wide-area-view boundary must

[24] The Real-Time Tools Survey did not explicitly explore this topic. The RTBPTF perspective is based solely on the professional expertise of the task force members.

include the wide area plus the bulk electric elements in adjacent areas that are collectively needed to ensure accurate analyses of SOLs and IROLs in the wide area.[25]

RTBPTF recommends that NERC and the RROs establish criteria for determining the “wide area boundary” and the RC’s “wide-area view.” RTBPTF recommends that the wide-area-view boundary should be determined based on an impact-based methodology – that is, a process to determine the critical flow and status information from adjacent reliability coordinator areas based on detailed system studies to allow the calculation of IROLs. These uniform formal criteria would clarify the extent and detail required for the “wide area.”

Regarding issues #1 and #2 above, RTBPTF recognizes that the criteria for defining “bulk electric system” and “wide area,” when applied to real-time operations and modeling, will directly affect the number of data required and thus will ultimately affect the content and size of the models used by network applications. RTBPTF’s recommended approach is intended to insure that the required elements of the bulk electric system are appropriately defined and that data for real-time operation and modeling are adequate. See the sidebar *RTBPTF Thoughts on Bulk Electric System, Wide-Area View, and Modeling Requirements* for an explanation of RTBPTF’s view of the interrelationship of issues #1 and #2 and their effect on real-time network models (issue #3 below).

Issue #3: Mandatory Procedures for Specifying Acceptable Reactive Reserves Should be Developed. Reactive reserves monitoring is a documented set of procedures, practices, or guidelines for maintaining awareness of current and near-term reactive reserve capability. Although current NERC standards define acceptable operating (real) reserves, they do not define acceptable reactive reserves. Defining reactive reserves is difficult because they must be evaluated with explicit consideration of network topology and the balance between reactive sources and sinks in local regions within the network. RTBPTF believes that mandatory requirements for real-time tools for reactive reserve monitoring would be highly desirable; however, before such recommendations can be formulated, NERC must define technically justified and feasible-to-implement requirements for determining the appropriate amount and location of acceptable reactive reserves and clarifying how reliability coordinators should monitor these reserves. This issue is explored more fully in Section 3.1, Reserve Monitoring, of this report.

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[25] That is, RTBPTF recommends that the wide-area-view boundary for RCs be referred to as “minimum boundary conditions based upon a defined set of system conditions, contingencies, and required performance criteria.” Operating Limit Definition Task Force (OLDTF). 2007. *Reliability Criteria and Operating Limits Concepts Reference Document - System Limits - Version 4, Draft 2*. January 29.

Issue #4: Mandatory Procedures for Determining Acceptable Load-Shed Capability Should be Developed. RTBPTF agrees with the *FERC Staff Assessment* that NERC standards do not adequately define requirements for load-shed capability. Thus, although situational awareness requires that operators know how much and how fast they can and must deploy load-shed resources (by means of an appropriate real-time tool), NERC must also make technical progress to define requirements for determining the correct amount, location, and maximum time-to-deploy of load-shed resources. This issue is explored more fully in Section 3.5, Load-Shed Capability, of this report.

Issue #5: External Modeling and Data Exchange Practices Should be Improved by Explicit Reference to the Definition of the Wide-Area-View Boundary. A consistent, uniform set of modeling and data exchange practices, procedures, and standards are needed to support creation and maintenance of accurate external models. RTBPTF recommends that these practices, procedures, and standards follow as a natural outgrowth of the definition of bulk electric system elements that are critical to a particular entity and that, therefore, define the wide-area-view boundary for that entity (per the discussion of issues #1 and #2 above). The complete discussion of this issue and the task force's specific recommendations concerning modeling practices are found in Sections 4.0, Power System Models; 4.1, Model Characteristics; and 4.2, Modeling Practices and Tools, of this report.

RTBPTF recommends that NERC create a new task force to focus specifically on recommending minimum standards for real-time models and data exchange, including:

- Grid change notification
- Model data exchange
- ICCP data exchange (see specific recommendations in Section 1.2, ICCP-Specific Data)
- Supplemental support data exchange (e.g., schematics, maps)
- Non-disclosure agreements

The task force recognizes the work already completed by the NERC Data Exchange Working Group (DEWG) in these areas, which is documented in the ISN Node Responsibilities and Procedures document.[26] The task force considers this work a good starting point for definitive and comprehensive requirements.

Issue #6: Adequate Funding and Staffing for Real-Time Tools and Support Should be Ensured. To ensure adequate monitoring and situational awareness, reliability entities' managers must understand the importance of real-time tools and commit to actively supporting required activities and staff. However, RTBPTF

[26] NERC Data Exchange Working Group (DEWG). 2005. *ISN Node Responsibilities and Procedures*. August 4.

was not able to analyze this issue both because significant differences among organizations made direct comparisons difficult and because this analysis requires expertise beyond that of the task force's members. RTBPTF recommends that OC determine an alternate means for addressing this issue.

Next Steps

RTBPTF emphasizes that this report is only the beginning of NERC and industry efforts to improve reliability through better real-time operating tools and practices. There is still much to do to implement the task force's recommendations for revised standards and operating guidelines and to conduct needed additional analyses.

To initiate the next steps in the process, RTBPTF proposes to finish work on the following activities, which will complete the remainder of the task force's scope of work as assigned by OC:

- Append recommendations for revised standards to the existing Standards Review Forms that are included in the NERC Standards Development Plan: 2007–2009.[27]
- Provide technical support to the standards drafting teams.
- Prioritize areas requiring more analysis.
- Write high-level scopes for the analysis required.

Following completion of these activities, RTBPTF will disband.

As described in the report, RTBPTF also recommends the following additional steps, which are outside the scope assigned to the task force by OC:

- ORS should determine how operating guidelines are to be developed and maintained.
- OC should consider asking the RROs to develop these guidelines as "supplements" to the NERC standards.
- NERC should address the areas in need of more analysis.

Organization of this Report

The remainder of this report is organized as follows:

Five major sections describe the findings, analysis, and task force recommendations for the main subject areas of the Real-Time Tools Survey, and a sixth section details the next steps toward implementing RTBPTF's recommendations:

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[27] ftp://www.nerc..com/pub/sys/all_updl/standards/sar/FERC_Filing_Volumes_I-II III_Reliability_Standards_Development_Plan_30Nov06.pdf

Section 1.0, Real-Time Data Collection
Section 2.0, Reliability Tools for Situational Awareness
Section 3.0, Situational Awareness Practices
Section 4.0, Power System Modeling
Section 5.0, Support and Maintenance Tools
Section 6.0, Next Steps

Within each section, a general introduction is followed by sections focusing on the main topic areas in that section. Each topical section is structured as follows:

- **Definition** of the specific topic
- **Background** on the specific topic, including blackout investigation findings related to it
- **Summary of Findings** based on the Real-Time Tools Survey responses
- **Recommendations for New Reliability Standards** (if applicable), including new reliability standards or modifications to existing standards, with rationale for each, and major issues to address to clarify interpretation of existing reliability standards in the context of real-time tools usage, practice, and processes that enhance situational awareness
- **Recommendations for Operating Guidelines** (if applicable), including recommendations and corresponding rationale for new operating guidelines, following the Best Practices Task Force conclusion that best practices are "good things to do" and should complement existing NERC reliability standards; operating guidelines are applicable across the industry, but are voluntary, not mandatory
- **Areas Requiring More Analysis** (if applicable), including recommendations that NERC further study a tool or topic about which the Real-Time Tools Survey results were inconclusive
- **Examples of Excellence** (if applicable), a brief notation that RTBPTF identified examples of excellence for the specific topic, which are detailed in Appendix E

The appendices to this report address Real-Time Tools Survey development (Appendix A), participation (Appendix B), analysis (Appendix C), and web links to aggregate survey results (Appendix D). Appendix E, Examples of Excellence, describes practices related to tools and/or operating procedures that exceed minimum requirements of existing standards, are unique to individual organizations, and may not be applicable throughout the industry.

The report also includes a glossary and an acronym list for the reader's convenience.

RTBPTF Thoughts on Bulk Electric System, Wide-Area View, and Modeling Requirements

RTBPTF suggests the following approach to defining bulk electric system elements, the wide-area-view boundary, and modeling requirements:

The list of bulk electric system elements that each reliability coordinator (RC) must maintain shall comprise the bulk electric system elements within the RC's footprint. Call the bulk electric system elements in this list the BES_{RC}.

The wide area that an RC must monitor shall include the BES_{RC} plus the bulk electric system elements in adjacent RC footprints that, individually, if they were out of service, could impact calculations of SOLs or IROLs beyond a yet-to-be-defined threshold. Call the wide area WA and this set of bulk electric system elements in adjacent areas the primary BES_{Adj}.

Thus:

$$WA = BES_{RC} + \text{primary } BES_{Adj}$$

The wide-area view of an RC is simply the information derived from modeling and real-time data made available to the RC operators to fulfill the requirements for monitoring, visualizing, and analyzing the wide area. The wide-area view can extend beyond the wide area.

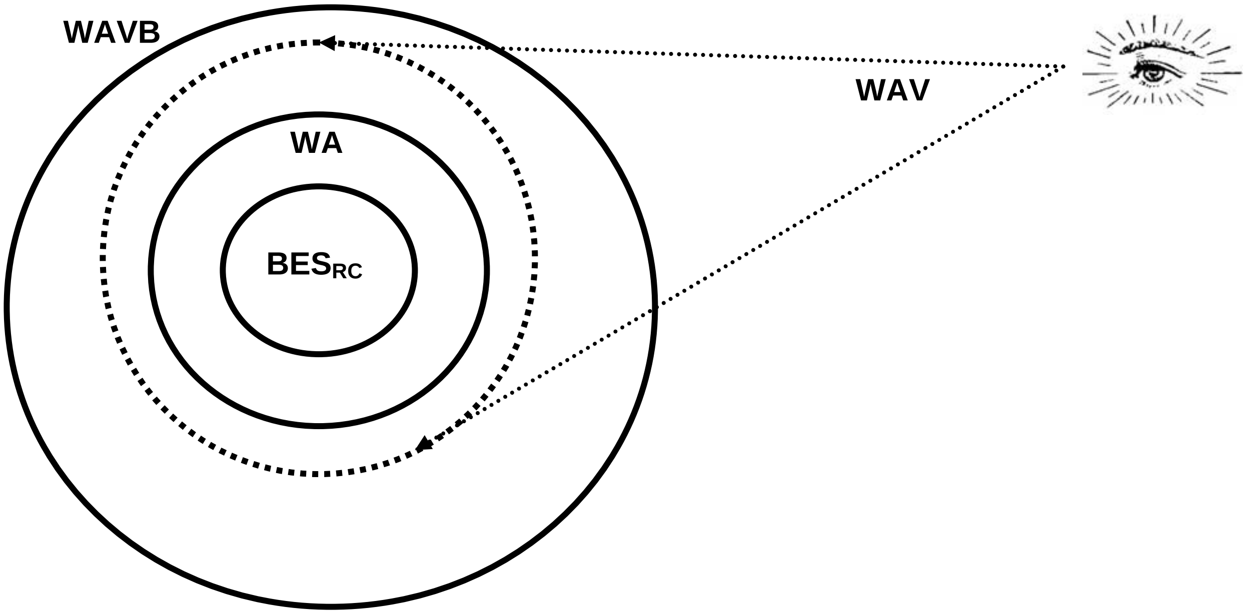
The wide-area-view boundary shall include the wide area plus the bulk electric elements in adjacent areas that are collectively needed to ensure accurate analyses of SOLs and IROLs in the wide area. Call the wide-area-view boundary WAVB and this set of bulk electric system elements the secondary BES_{Adj}.

Thus:

$$WAVB = WA + \text{secondary } BES_{Adj}$$

The internal portion of an RC's real-time network model shall include, at a minimum, the BES_{RC} and any other facilities in the RC footprint needed to ensure accurate analyses of SOLs and IROLs in that RC's footprint.

The external portion of a reliability coordinator's real-time network model shall include, at a minimum, the WAVB.


WAVB
WAV
WA
BES$_{RC}$

Reliability Toolbox Recommendation and Rationale

The RTBPTF recommendation that five real-time tools be required of all reliability coordinators (RCs) and transmission operators (TOPs) addresses tools that are covered in several discrete sections of this report (Section 1.1, Telemetry Data; Section 2.1, Alarm Tools; Section 2.3, Network Topology Processor; Section 2.5, State Estimator; Section 2.6, Contingency Analysis). Therefore, the task force presents the full text of this overarching recommendation separately below, using the same format as for the other recommendations in the specific sections throughout the report.

RTBPTF was charged with defining minimally acceptable capabilities for network analysis and situational awareness tools. By recommending the mandatory tools that make up the Reliability Toolbox as well as specific performance standards and metrics for these tools, RTBPTF believes it has fulfilled this charge to the best of its ability, given the current state of the industry as measured in the Real-Time Tools Survey. All five of the recommended tools enjoy widespread usage in the industry and support the fundamental purpose of maintaining situational awareness and reliable operation of the bulk electric system. The Reliability Toolbox and related performance standards and metrics are technically defensible for today's electric industry, as indicated by the survey results, and will help realize the full potential of these tools. Over time, it may be necessary to reconsider the minimal capabilities of these tools or to consider whether other tools need to be added to the toolbox.

RTBPTF Recommendation

To mandate the Reliability Toolbox, RTBPTF recommends that a new requirement be established under the current Standard TOP-006 (Monitoring System Conditions) to specify the minimum set of monitoring and analysis tools implicitly required by Standard IRO-002 and Standard TOP-008 – that is, to specify the minimum set of tools necessary to monitor the bulk electric system and maintain operator situational awareness. The new standard shall apply to both RCs and TOPs[28]:

PR1. Reliability Monitoring and Analysis Tools (Reliability Toolbox). Each reliability coordinator and transmission operator shall have adequate monitoring and analysis tools to maintain situational awareness for his/her respective areas of responsibility.[29] The following monitoring and analysis tools are mandatory:

[28] Proposed requirements are designated "PR," and proposed measures are designated "PM."

[29] RTBPTF recognizes that differences will arise naturally between TOPs and RCs in their use of the tools. For example, the definition of the wide-area boundary (for RCs) and the "local"

- Alarm tools
- Telemetry data systems
- Network topology processor
- State estimator
- Contingency analysis

RTBPTF recommends the following measure for the requirement stated above:

> PM1. Each reliability coordinator and transmission operator shall have and provide upon request evidence that shall include, but is not limited to, the following:

- Documentation from suppliers
- Operating and support staff training documents and users' guides
- Tool maintenance and support documents
- Logs/records of tool availability and tool output results
- Displays and/or visualization tools that show data from these tools
- Other equivalent evidence to show that it has the monitoring analysis tools in accordance with Requirement PR1 and that the tools are functioning and being used as planned

Rationale

Existing NERC reliability standards require the use of monitoring and analysis tools to aid operators in maintaining situational awareness of the bulk electric system. However, these standards do not explicitly require specific tools and are not globally applicable to all users of such tools. For example, Standard TOP-008 (Response to Transmission Limit Violations) exists, "[t]o ensure Transmission Operators take actions to mitigate SOL and IROL violations."[30] Requirement R4 of this standard states, "[t]he Transmission Operator shall have ***sufficient*** [emphasis added] information and ***analysis tools*** [emphasis added] to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation." This standard applies only to transmission operators.

Similarly, standard IRO-002 (Reliability Coordination – Facilities) states, "Reliability Coordinators need information, ***tools*** [emphasis added] and other capabilities to perform their responsibilities." Requirement R7 of this standard states, "[e]ach Reliability Coordinator shall have ***adequate analysis tools***

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transmission system (for TOPs) will have implications for the scope of the network model that each relies upon.

[30] Quotation taken from the purpose statement in section A.3 of NERC Reliability Standard TOP-008-1

[emphasis added] such as state estimation, pre and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays." Requirement R9 states, "[e]ach Reliability Coordinator shall control its Reliability Coordinator ***analysis tools*** [emphasis added], including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of ***analysis tool*** [emphasis added] outages." This standard applies only to reliability coordinators.

RTBPTF believes that Standard TOP-006 is the most appropriate standard in which to incorporate the mandatory tools requirement because this standard is applicable to both RCs and TOPs. In addition, Standard TOP-006 clearly focuses on ensuring that "critical reliability parameters are monitored in real-time."[31] To ensure that critical reliability parameters are monitored in real time, NERC reliability standards must specify a minimum set of tools. The Reliability Toolbox comprises those tools.

RTBPTF believes that the "analysis tools" prescribed by both Standard IRO-002 (Requirement R7) and Standard TOP-008 (Requirement R4) refer to the same set of monitoring and analysis tools even allowing for the natural differences in the use of these tools by TOPs and RCs arising from their different responsibilities as specified by the NERC Functional Model. Locating the Reliability Toolbox requirement in Standard TOP-006, which applies to both reliability coordinators and transmission operators, mandates a uniform minimum set of tools for both RCs and TOPs. It also clarifies and makes specific the term "sufficient information and analysis tools" in Standard TOP-008 (Requirement R4) and the term "adequate analysis tools" in Standard IRO-002 (Requirement R7).

Applicability Statement

Even though the Reliability Toolbox is recommended to be mandatory for only RCs and TOPs, the task force realizes that other entities such as transmission owners and balancing authorities use some or all of these tools as well. In the particular technical sections of this report addressing the individual tools, RTBPTF recommends specific requirements for the use, availability, and performance of these tools, and further recommends in those sections that these requirements apply to all users of the tools. Specifically, any entity not registered in the NERC Functional Model as an RC or a TOP, but that uses any of these tools to support or complement their RC's or TOP's ability to operate the bulk electric system reliably in accordance with formal agreements, contracts, or previously established practices or procedures, shall also be subject to compliance with the specific requirements for the tools.

[31] Quotation taken from the purpose statement in section A.3 of NERC Reliability Standard TOP-006-1.

Section 1.0
Real-Time Data Collection

Introduction

Collecting real-time data on power system status is the first and most elementary step in the complex process of developing the information that electric system operators need to maintain situational awareness. Real-time reliability tools such as the state estimator and contingency analysis can only provide results that accurately represent current and potential reliability problems if these tools have real-time power-flow and voltage values and status data for other elements included in their models. The accuracy of the information that real-time reliability tools provide depends on the accuracy of the data supplied to the tools.

The quality of the results that real-time reliability tools produce is also influenced by the breadth and depth of the portion of the bulk electric system for which real-time data are collected, relative to the breadth and depth of the relevant reliability entity's area of responsibility. Thus, how we define the elements that constitute the bulk electric system is very important for the information that operators reply to for situational awareness.

To assess current industry practice regarding real-time data collection, the Real-Time Data Collection portion of the Real-Time Tools Survey focused on telemetry, ICCP-specific, and miscellaneous data (weather, fault locator, and high-speed sampled data). The survey findings for each type of data are presented in the Sections 1.1-1.3. These sections are summarized below:

- **Section 1.1, Telemetry Data** — This section summarizes the types of real- and near-real-time data collected by telemetry systems for use in EMSs to monitor the bulk electric system. Telemetry data are typically status and analog values that are updated continuously in real or near-real time. These data allow operators to determine, in real- or near-real time, the state of the interconnected bulk electric system. For operators to reliably run the system in a coordinated manner under normal and abnormal conditions, telemetry data systems must function with a high degree of availability. Therefore, tools and practices related to telemetry data availability are important for system reliability and operator situational awareness.

  Section 1.1 also addresses the conversion of real-time data into useful information for operators. The *FERC Staff Assessment* of NERC's proposed reliability standards[1] states:

[1] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp. Referred to in this document as the *FERC Staff Assessment*.

> … while the requirements identify the data to be gathered, they fail to describe the tools necessary to turn that data into critical reliability parameters, i.e., system capability or contingency analysis, which are required to achieve situational awareness. Reliability Coordinators, Transmission Operators, and Balancing Authorities must be aware of the status of their respective systems, and such situational awareness cannot be obtained by viewing massive amounts of raw data.

RTBPTF agrees that the NERC standards generally fail to describe the tools necessary for monitoring "critical reliability parameters." Section 1.1 gives a snapshot of the types of telemetry data currently being collected throughout the industry, describes the Real-Time Tools Survey findings related to telemetry data, and discusses the tools necessary to comply with NERC standards that require reliability entities to "monitor" specific data and bulk electric system elements and parameters.

Section 1.1 also explores the definition of bulk electric system elements.

- **Section 1.2, ICCP-Specific Data** — ICCP is a standard data-exchange format widely used in the electric utility industry to communicate information among operating entities. The NERC ISN uses ICCP for data exchange among reliability coordinators. Several intra-regional and intra-company networks also use this protocol to provide data to RCs from operating entities within the RC's footprint. Section 1.2 addresses the management of and methodology for ICCP data exchange and examines issues and practices that affect the adequacy, quality, and timeliness of ICCP data supplied to real-time tools that analyze bulk electric system reliability.

- **Section 1.3, Miscellaneous Data** — Miscellaneous data are used by real-time applications/tools that may not be supported by basic SCADA and/or ICCP systems. Section 1.3 addresses: 1) meteorological data, such as from commercial weather services, 2) fault locater data, such as from protective relays that can calculate the distance from the relay location to the location of a transmission-line fault, and 3) high-speed sampled data, such as from sequence-of-event recorders and phasor monitoring units (PMUs).

Significance to the August 14, 2003 Blackout

The U.S.-Canada Power System Outage Task Force analysis of the August 14, 2003[2] blackout identified the failure of the interconnected grid's reliability organizations to provide effective real-time diagnostic support as one cause of the blackout. Specifically, the reliability data that MISO received via the East Central Area Reliability Council (ECAR) data network and other data links were not mapped so that MISO's state estimator could be automatically informed of the status change in key transmission lines.

RTBPTF Recommendations for New Reliability Standards

In Sections 1.1 through 1.3, RTBPTF recommends that several new requirements be added to existing standards:

- Each RC must compile and maintain a list of all bulk electric system elements within its area of responsibility.
- New requirements and measures must be added pertaining to RC monitoring of the bulk electric system.
- Data exchange standards must be developed to address change management and coordination, data access restrictions, naming conventions, joint testing and data checkout, system interoperability, quality codes, and dispute resolution.
- Standards must be developed for data availability, and a process must be developed for trouble resolution and escalation.
- A new requirement must be developed addressing the importance of weather data for situational awareness and real-time operational capabilities. Specifically, operators must be provided dynamically updated real-time and forecasted weather data so that they can readily determine current and near-term weather conditions that might affect how they need to monitor or operate their systems.

[2] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. Referred to in this document as the *Outage Task Force Final Blackout Report.*

Section 1.1
Telemetry Data

Definition

Telemetry data are status and analog values originating from conventional SCADA/EMS or equivalent systems (telemetry data systems) and are updated continuously in real-time or near-real-time operation. These data may come directly from SCADA system(s) or from direct connection (ICCP, ISN, etc.) to SCADA systems operated by others.

Background

Telemetry data from direct connections to internal systems (i.e., from SCADA/EMS or equivalent systems) and/or direct connections to external systems operated by others (i.e., ICCP data links) allow operators to determine, in real or near-real time, the state of the interconnected bulk electric system. To reliably operate the system in a coordinated manner under normal and abnormal conditions as defined in NERC standards, operators must have telemetry data and corresponding telemetry data systems available. Telemetry data and systems are essential to NERC's mandated real-time monitoring capability; tools and practices related to telemetry data availability are important for system reliability and operator situational awareness.

The *FERC Staff Assessment* of NERC's proposed reliability standards[3] states:

> … while the requirements identify the data to be gathered, they fail to describe the tools necessary to turn that data into critical reliability parameters, i.e., system capability or contingency analysis, which are required to achieve situational awareness. Reliability Coordinators, Transmission Operators, and Balancing Authorities must be aware of the status of their respective systems, and such situational awareness cannot be obtained by viewing massive amounts of raw data.

RTBPTF agrees with the FERC staff conclusions above. NERC standards generally fail to describe the necessary tools for monitoring "critical reliability parameters."

The telemetry data section of the Real-Time Tools Survey was designed to take a snapshot of current availability of certain types of telemetry data throughout the

[3] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

industry. The Real-Time Tools Survey also determined what telemetry data are available from bulk electric system elements currently used by reliability entities. This section of the report describes the survey findings related to telemetry data, discusses the tools necessary to comply with NERC standards that involve use of telemetry data, and presents RTBPTF's recommended requirements for using these tools. This section also discusses issues related to the definition and the interpretation of the term "bulk electric system." RTBPTF reinforces the importance of the resolution of this definition as it affects task force's recommendations. RTBPTF recognizes that entities cannot be expected to use specific tools to monitor the "bulk electric system" without stipulating which components of the bulk electric system are to be monitored or require telemetry data.

Summary of Findings

The subsections below summarize the Real-Time Tools Survey responses regarding telemetry data for generators, transmission lines and transformers, and substation switching devices, as well as telemetry data maintenance and support practices.

Most survey respondents (97 percent, 58 out of 60) indicated that their organizations use telemetry data. An overwhelming majority (96 percent, 54 out of 57) of respondents that have operational telemetry data systems rate the availability of telemetry data as "essential" for situational awareness. This concurrence of opinion is uniform across the types of entities that participated in the survey (RCs, TOPs, BAs). Respondents expressed most concern about the quantity of data available from their systems. For example, one respondent said that "a large network [model] and lack of real time telemetry is one of the biggest issues" with which that respondent deals in "real time network modeling."

Most respondents reported that they receive telemetry data through a combination of direct connection to a SCADA/EMS system (89 percent, 51 out of 57) and/or direct ICCP connections to other utilities/systems (84 percent, 48 out of 57). The applications most commonly reported as using telemetry data were the network topology processor (70 percent, 40 out of 57 respondents), state estimator (77 percent, 44 out of 57), alarm tools (98 percent, 56 out of 57), and visualization tools (81 percent, 46 out of 57).

Generator Telemetry Data

This subsection summarizes the findings for telemetry data from generating units. All respondents reported that they have some form of generator telemetry data available; 95 percent of respondents rated the availability of generator data "essential" to enhancing situational awareness.

Generator Data within Respondent's Area of Responsibility

Respondents were asked to quantify the telemetry data ("all," "most," "some," or "none") they receive from central station generating units within their areas of responsibility. Table 1.1-1 summarizes the responses. The number of respondents selecting the answer listed at the top of a column is given followed by the total number of respondents and the equivalent percentage of respondents (i.e., 36/55=65% indicates that 36 out of 55 respondents or 65 percent of respondents chose this answer). Data are presented in this manner throughout this section.

Type of Generator Telemetry Data	What Telemetry Data do You Receive for Central Station Generating Units Within Your Area of Responsibility?			
	All	Most	Some	None
Total net plant output (MW and Mvar)	36/55=65 %	10/55=18 %	7/55=13 %	2/55=4 %
Unit connection status	36/57=63 %	17/57=30 %	3/57=5 %	1/57=2 %
Unit status (Offline, outage, base load, regulating, etc.)	27/55=49 %	16/55=29 %	9/55=16 %	3/55=5 %
Unit output at the generator terminals (MW and Mvar)	27/56=48 %	23/56=41 %	5/56=9 %	1/56=2 %
Unit-connected station service loads (MW and Mvar)	8/57=14 %	20/57=35 %	19/57=33 %	10/57=18 %
Common station service loads (MW and Mvar)	8/56=14 %	19/56=34 %	22/56=39 %	7/56=13 %
Net unit output at the high side of the step-up transformer (MW and Mvar)	21/57=37 %	18/57=32 %	16/57=28 %	2/57=4 %
Operating Limits (MW)	19/57=33 %	14/57=25 %	11/57=19 %	13/57=23 %
Operating Limits (Mvar)	11/57=19 %	8/57=14 %	8/57=14 %	30/57=53 %
Automatic Voltage Regulator (AVR) Status	3/57=5 %	8/57=14 %	16/57=28 %	30/57=53 %
Stabilizer Status	4/53=8 %	3/53=6 %	7/53=13 %	39/53=74 %
Ramp Rate Capability	10/56=18 %	6/56=11%	14/56=25 %	26/56=46 %
Governor Status	1/53=2 %	1/53=2 %	8/53=15 %	43/53=81 %

Table 1.1-1 — Generator Telemetry Data Within Respondents' Areas of Responsibility — All Respondents

Table 1.1-1 shows that generator total net output (MW and Mvar) and corresponding generator status are the most common forms of generator telemetry data received by respondents within their areas of responsibility. The survey results also reveal that the majority of entities do not receive MW and/or Mvar operating limits. RTBPTF infers that respondents may be using static MW and/or Mvar generator operating limits in lieu of telemetered data. The majority of respondents do not receive other forms of generator telemetry data [i.e., automatic voltage regulator (AVR) status, stabilizer status, etc.] from their telemetry data systems. RC responses to the questions listed in Table 1.1-1 are broken out in Table 1.1-2. The percentages for RC responses are similar to those for all respondents.

Type of Generator Telemetry Data	What Telemetry Data do You Receive for Central Station Generating Units Within Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
Total net plant output (MW and Mvar)	13/17=76 %	2/17=12 %	2/17=12 %	0/17=0 %
Unit connection status	11/18=61 %	5/18=28 %	2/18=11 %	0/18=0 %
Unit status (Offline, outage, base load, regulating, etc.)	9/17=53 %	3/17=18 %	4/17=24 %	1/17=6 %
Unit output at the generator terminals (MW and Mvar)	9/18=50 %	7/18=39 %	2/18=11 %	0/18=0 %
Unit-connected station service loads (MW and Mvar)	1/18=6 %	5/18=28 %	8/18=44 %	4/18=22 %
Common station service loads (MW and Mvar)	1/18=6 %	5/18=28 %	9/18=50 %	3/18=17 %
Net unit output at the high side of the step-up transformer (MW and Mvar)	4/18=22 %	7/18=39 %	7/18=39 %	0/18=0 %
Operating Limits (MW)	6/18=33 %	3/18=17 %	5/18=28 %	4/18=22 %
Operating Limits (Mvar)	4/18=22 %	2/18=11 %	3/18=17 %	9/18=50 %
AVR Status	0/18=0 %	5/18=28 %	9/18=50 %	4/18=22 %
Stabilizer Status	2/17=12 %	2/17=12 %	3/17=18 %	10/17=59 %
Ramp Rate Capability	2/18=11 %	3/18=17 %	4/18=22 %	9/18=50 %
Governor Status	0/17=0 %	0/17=0 %	3/17=18 %	14/17=82 %

Table 1.1-2 — Generator Telemetry Data within Respondents' Areas of Responsibility — RCs only

Generator Data for Adjacent Areas

The survey asked respondents to quantify the telemetry data ("all," "most," "some," or "none") they receive for central station generating units from areas adjacent to the respondents' areas of responsibility. Table 1.1-3 summarizes the responses.

Type of Generator Telemetry Data	What Telemetry Data do You Receive for Central Station Generating Units from Areas Adjacent to Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
Total net plant output (MW and Mvar)	5/55=9 %	4/55=7 %	28/55=51 %	18/55=33 %
Unit connection status	2/56=4 %	5/56=9 %	32/56=57 %	17/56=30 %
Unit status (Offline, outage, base load, regulating, etc.)	1/55=2 %	2/55=4 %	18/55=33 %	34/55=62 %
Unit output at the generator terminals (MW and Mvar)	2/56=4 %	4/56=7 %	28/56=50 %	22/56=39 %
Unit-connected station service loads (MW and Mvar)	0/56=0 %	2/56=4 %	12/56=21 %	42/56=75 %
Common station service loads (MW and Mvar)	0/56=0 %	2/56=4 %	11/56=20 %	43/56=77 %
Net unit output at the high side of the step-up transformer (MW and Mvar)	2/56=4 %	3/56=5 %	28/56=50 %	23/56=41 %
Operating Limits (MW)	1/55=2 %	1/55=2 %	4/55=7 %	49/55=89 %
Operating Limits (Mvar)	1/56=2 %	1/56=2 %	2/56=4 %	52/56=93 %
AVR Status	0/55=0 %	0/55=0 %	2/55=4 %	53/55=96 %
Stabilizer Status	0/55=0 %	0/55=0 %	2/55=4 %	53/55=96 %
Ramp Rate Capability	0/55=0 %	0/55=0 %	3/55=5 %	52/55=95 %
Governor Status	0/55=0 %	0/55=0 %	0/55=0 %	55/55=100 %

Table 1.1-3 — Generator Telemetry Data in Areas Adjacent to Respondents' Areas of Responsibility — All Respondents

Table 1.1-3 shows that the vast majority of respondents do not receive generator telemetry data from areas adjacent to their areas of responsibility. These responses are explained by the lack of specific criteria for the number of adjacent-area telemetry data needed to fulfill monitoring requirements for a "wide-area" view. Table 1.1-4 breaks out RC responses to the questions in Table 1.1-3. The percentages for RC responses are similar to those for all respondents.

Type of Generator Telemetry Data	What Telemetry Data do You Receive for Central Station Generating Units from Areas Adjacent to Your Area of Responsibility?			
	All	**Most**	**Some**	**None**
Total net plant output (MW and Mvar)	2/17=12 %	3/17=18 %	8/17=47 %	4/17=24 %
Unit connection status	2/18=11 %	5/18=28 %	10/18=56 %	1/18=6 %
Unit status (Offline, outage, base load, regulating, etc.)	1/17=6 %	2/17=12 %	8/17=47 %	6/17=35 %
Unit output at the generator terminals (MW and Mvar)	2/18=11 %	4/18=22 %	10/18=56 %	2/18=11 %
Unit-connected station service loads (MW and Mvar)	0/18=0 %	2/18=11 %	5/18=28 %	11/18=61 %
Common station service loads (MW and Mvar)	0/18=0 %	2/18=11 %	6/18=33 %	10/18=56 %
Net unit output at the high side of the step-up transformer (MW and Mvar)	2/18=11%	2/18=11 %	10/18=56 %	4/18=22 %
Operating Limits (MW)	1/18=6 %	1/18=6 %	2/18=11 %	14/18=78 %
Operating Limits (Mvar)	1/18=6 %	1/18=6 %	1/18=6 %	15/18=83 %
AVR Status	0/17=0 %	0/17=0 %	1/17=6 %	16/17=94 %
Stabilizer Status	0/17=0 %	0/17=0 %	1/17=6 %	16/17=94 %
Ramp Rate Capability	0/17=0 %	0/17=0 %	0/17=0 %	17/17=100 %
Governor Status	0/17=0 %	0/17=0 %	0/17=0 %	17/17=100 %

Table 1.1-4 — Generator Telemetry Data in Areas Adjacent to Respondents' Areas of Responsibility — RCs only

Generator Data for Other Units Affecting Respondent's Area of Responsibility

The survey asked respondents to quantify the telemetry data ("all," "most," "some," or "none") they receive for other types of generators that affect their area of responsibility [i.e., independent power producers (IPPs), distributed generation]. Table 1.1-5 summarizes the responses. The table shows that the majority of respondents do not receive generator telemetry data from other units that may affect their areas of responsibility. Note that IPPs may have a significant impact on an entity's area of responsibility.

Type of Generator Telemetry Data	Do You Receive Real-Time Data for Other Units Affecting Your Area of Responsibility?			
	All	Most	Some	None
IPPs	21/55=38 %	10/55=18 %	11/55=20 %	13/55=24 %
Distributed generation at cogeneration or customer locations	6/57=11 %	10/57=18 %	18/57=32 %	23/57=40 %
Customer loads participating in generation ancillary service	6/55=11 %	6/55=11 %	4/55=7 %	39/55=71 %
Generating plants beyond adjacent areas of your responsibility	2/57=4 %	5/57=9 %	13/57=23 %	7/57=65 %

Table 1.1-5 — Other Types of Generator Telemetry Data from Areas Adjacent to Respondents' Areas of Responsibility

Special or Calculated Generator Data

The survey asked respondents to quantify the telemetry data ("all," "most," "some," or "none") received for any special, real-time calculation for generating units in or adjacent to their areas of responsibility. Table 1.1-6 summarizes the responses Respondents do not commonly receive these types of data.

Special Generator Telemetry Data Type	Do You Use Any Special, Real-Time Calculation for Generating Units In or Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Substitute for any values at generating units not available by SCADA	1/51=2 %	1/51=2 %	19/51=37 %	30/51=59 %
Supplemental available data (such as reserve levels, hours of fuel, etc.)	3/53=6 %	1/53=2 %	11/53=21 %	38/53=72 %

Table 1.1-6 — Generator Telemetry Data for Special Real-Time Calculations In or Adjacent to Respondents' Areas of Responsibility

Transmission-Line Telemetry Data

This subsection summarizes survey findings regarding telemetry data for transmission lines. All respondents have some form of transmission-line telemetry data available, and 96 percent rated availability of transmission-line data as "essential" for enhancing situational awareness.

Transmission-Line Data within Respondents' Areas of Responsibility

The survey asked respondents to quantify the telemetry data ("all," "most," "some," or "none") they receive for transmission lines [345-765 kilovolt (kV)] within their areas of responsibility. Table 1.1-7 summarizes the responses.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (345-765 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	38/52=73 %	5/52=10 %	1/52=2 %	8/52=15 %
MW and Mvar flow on both ends	31/53=58 %	13/53=25 %	0/53=0 %	9/53=17 %
Current flow magnitude (Amperes) at either end	8/51=16 %	6/51=12 %	7/51=14 %	30/51=59 %
Current flow phase angle (degrees) at either end	0/51=0 %	2/51=4 %	5/51=10 %	44/51=86 %
Megavoltamperes (MVA) flow at either end	4/52=8 %	5/52=10 %	3/52=6 %	40/52=77 %
Real-time operating limits determined by substation equipment/systems	10/52=19 %	1/52=2 %	5/52=10 %	36/52=69 %
Line connection status	37/52=71 %	6/52=12 %	1/52=2 %	8/52=15 %
Line availability status (Tagged out, damaged, grounded, etc.)	18/51=35 %	1/51=2 %	4/51=8 %	28/51=55 %
kV on at least one end	36/52=69 %	7/52=13 %	1/52=2 %	8/52=15 %
kV on both ends	27/52=52 %	11/52=21 %	4/52=8 %	10/52=19 %

Table 1.1-7 — Telemetry Data for Transmission Lines (345-765 kV) Within Respondents' Areas of Responsibility — All Respondents

Table 1.1-7 shows that MW and Mvar flows, line connection status, and kV on at least one end are the most common forms of transmission-line telemetry data that respondents receive for 345 to 765-kV transmission lines within their areas of responsibility. Respondents report that their telemetry data systems provide either "all" or "most" of these data. The survey results also reveal that the majority of respondents do not receive MW and/or Mvar operating limit data. RTBPTF infers that respondents may be using static MW and/or Mvar transmission-line operating limits in lieu of telemetered data. The majority of respondents do not receive other forms of transmission-line telemetry data (i.e., current flow magnitude, phase angle measurements) within their areas of responsibility. Table 1.1-8 summarizes responses to this survey question from RCs only regarding transmission-line data. The percentages for reliability coordinators' responses are similar to those for all respondents.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (345-765 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	13/17=76 %	3/17=18 %	0/17=0 %	1/17=6 %
MW and Mvar flow on both ends	10/17=59 %	7/17=41 %	0/17=0 %	0/17=0 %
Current flow magnitude (Amperes) at either end	4/16=25 %	0/16=0 %	3/16=19 %	9/16=56 %
Current flow phase angle (degrees) at either end	0/16=0 %	0/16=0 %	2/16=13 %	14/16=88 %
MVA flow at either end	0/17=0 %	2/17=12 %	2/17=12 %	13/17=76 %
Real-time operating limits determined by substation equipment/systems	4/17=24 %	1/17=6 %	4/17=24 %	8/17=47 %
Line connection status	12/17=71 %	5/17=29 %	0/17=0 %	0/17=0 %
Line availability status (tagged out, damaged, grounded, etc.)	6/16=38 %	0/16=0 %	2/16=13 %	8/16=50 %
kV on at least one end	10/17=59 %	5/17=29 %	1/17=6 %	1/17=6 %
kV on both ends	8/17=47 %	5/17=29 %	3/17=18 %	1/17=6 %

Table 1.1-8 — Telemetry Data for Transmission Lines (345-765 kV) Within Respondents' Areas of Responsibility — RCs only

The survey asked respondents to quantify telemetry data (“all,” “most,” “some,” or “none”) they receive for transmission lines (100 to 230 kV) within their areas of responsibility. Table 1.1-9 summarizes the responses. For 100- to 230-kV voltage transmission lines, telemetry data for MW and Mvar flows, line connection status, and kV on at least one end are the most common telemetry data that respondents receive within their areas of responsibility although these data are not as common as data for 345- to 765-kV transmission lines. For 345- to 765-kV transmission lines, the majority of respondents do not receive data on MW and/or Mvar operating limits. RTBPTF infers that entities may be using static MW and/or Mvar transmission line operating limits in lieu of telemetered data.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (100-230 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	29/56=52 %	24/56=43 %	3/56=5 %	0/56=0 %
MW and Mvar flow on both ends	13/57=23 %	32/57=56 %	12/57=21 %	0/57=0 %
Current flow magnitude (Amperes) at either end	9/55=16 %	10/55=18 %	11/55=20 %	25/55=45 %
Current flow phase angle (degrees) at either end	0/54=0 %	0/54=0 %	8/54=15 %	46/54=85 %
MVA flow at either end	12/55=22 %	5/55=9 %	1/55=2 %	37/55=67 %
Real-time operating limits determined by substation equipment/systems	9/56=16 %	5/56=9 %	11/56=20 %	31/56=55 %
Line connection status	30/56=54 %	19/56=34 %	3/56=5 %	4/56=7 %
Line availability status (Tagged out, damaged, grounded, etc.)	19/55=35 %	12/55=22 %	1/55=2 %	23/55=42 %
kV on at least one end	32/55=58 %	19/55=35 %	4/55=7 %	0/55=0 %
kV on both ends	13/57=23 %	30/57=53 %	13/57=23 %	1/57=2 %

Table 1.1-9 — Telemetry Data for 100- to 230-kV Transmission Lines Within Respondents' Areas of Responsibility

Respondents were also asked to quantify telemetry data ("all," "most," "some," or "none") they receive for transmission lines less than 100 kV within their areas of responsibility. Table 1.1-10 summarizes the responses. The majority of respondents do not receive telemetry data for less-than-100-kV transmission lines within their areas of responsibility.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (<100 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	16/56=29 %	24/56=43 %	14/56=25 %	2/56=4 %
MW and Mvar flow on both ends	10/57=18 %	17/57=30 %	25/57=44 %	5/57=9 %
Current flow magnitude (Amperes) at either end	5/55=9 %	14/55=25 %	8/55=15 %	28/55=51 %
Current flow phase angle (degrees) at either end	0/54=0 %	0/54=0 %	1/54=2 %	53/54=98 %
MVA flow at either end	5/56=9 %	5/56=9 %	6/56=11 %	40/56=71 %
Real-time operating limits determined by substation equipment/systems	8/57=14 %	2/57=4 %	6/57=11 %	41/57=72 %
Line connection status	17/56=30 %	24/56=43 %	9/56=16 %	6/56=11 %
Line availability status (Tagged out, damaged, grounded, etc.)	16/56=29 %	8/56=14 %	4/56=7 %	28/56=50 %
kV on at least one end	20/56=36 %	20/56=36 %	15/56=27 %	1/56=2 %
kV on both ends	7/57=12 %	17/57=30 %	26/57=46 %	7/57=12 %

Table 1.1-10 — Telemetry Data for less-than-100-kV Transmission Lines Within Respondents' Areas of Responsibility

Transmission-Line Data for Adjacent Areas

The survey asked respondents to quantify telemetry data ("all," "most," "some," or "none") they receive for transmission lines (345 to 765 kV) in areas adjacent to their areas of responsibility. Table 1.1-11 summarizes the responses.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (345-765 kV) From Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	10/56=18 %	12/56=21 %	26/56=46 %	8/56=14 %
MW and Mvar flow on both ends	5/56=9 %	3/56=5 %	30/56=54 %	18/56=32 %
Current flow magnitude (Amperes) at either end	3/54=6 %	1/54=2 %	11/54=20 %	39/54=72 %
Current flow phase angle (degrees) at either end	0/54=0 %	0/54=0 %	2/54=4 %	52/54=96 %
MVA flow at either end	1/55=2 %	2/55=4 %	8/55=15 %	44/55=80 %
Real-time operating limits determined by substation equipment/systems	3/55=5 %	0/55=0 %	4/55=7 %	48/55=87 %
Line connection status	10/56=18 %	6/56=11 %	24/56=43 %	16/56=29 %
Line availability status (Tagged out, damaged, grounded, etc.)	5/56=9 %	1/56=2 %	5/56=9 %	45/56=80 %
kV on at least one end	9/56=16 %	9/56=16 %	26/56=46 %	12/56=21 %
kV on both ends	4/56=7 %	4/56=7 %	23/56=41 %	25/56=45 %

Table 1.1-11 — Telemetry Data for Transmission Lines (345-765 kV) in Areas Adjacent to Respondents' Areas of Responsibility — All Respondents

Table 1.1-11 shows that the majority of respondents do not receive transmission-line telemetry data from adjacent areas. This may be explained by the lack of specific criteria for the adjacent-area telemetry data needed to fulfill monitoring requirements for "wide-area" view. Table 1.1-12 shows responses for RCs only regarding transmission-line telemetry data from adjacent areas. The percentages for RCs' responses are similar to those for all respondents.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (345-765 kV) from Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	6/18=33 %	9/18=50 %	3/18=17 %	0/18=0 %
MW and Mvar flow on both ends	4/18=22 %	7/18=39 %	7/18=39 %	0/18=0 %
Current flow magnitude (Amperes) at either end	1/17=6 %	3/17=18 %	3/17=18 %	10/17=59 %
Current flow phase angle (degrees) at either end	0/17=0 %	0/17=0 %	0/17=0 %	17/17=100 %
MVA flow at either end	1/18=6 %	2/18=11 %	1/18=6 %	14/18=78 %
Real-time operating limits determined by substation equipment/systems	2/18=11 %	4/18=22 %	5/18=28 %	7/18=39 %
Line connection status	8/18=44 %	6/18=33 %	3/18=17 %	1/18=6 %
Line availability status (Tagged out, damaged, grounded, etc.)	4/16=25 %	3/16=19 %	1/16=6 %	8/16=50 %
KV on at least one end	8/18=44 %	6/18=33 %	4/18=22 %	0/18=0 %
KV on both ends	4/18=22 %	5/18=28 %	8/18=44 %	1/18=6 %

Table 1.1-12 — Telemetry Data for Transmission Lines (345-765 kV) from Adjacent Areas — RCs Only

Respondents were asked to quantify telemetry data they receive (“all,” “most,” “some,” or “none”) for transmission lines (100-230 kV) from areas adjacent to their areas of responsibility. Table 1.1-13 summarizes the responses. The majority of respondents do not receive telemetry data for transmission lines (100-230 kV) in adjacent areas.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (100-230 kV) from Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	7/55=13 %	7/55=13 %	34/55=62 %	7/55=13 %
MW and Mvar flow on both ends	3/55=5 %	5/55=9 %	31/55=56 %	16/55=29 %
Current flow magnitude (Amperes) at either end	2/52=4 %	0/52=0 %	11/52=21 %	39/52=75 %
Current flow phase angle (degrees) at either end	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
MVA flow at either end	2/52=4 %	0/52=0 %	9/52=17 %	41/52=79 %
Real-time operating limits determined by substation equipment/systems	1/53=2 %	1/53=2 %	6/53=11 %	45/53=85 %
Line connection status	9/54=17 %	3/54=6 %	30/54=56 %	12/54=22 %
Line availability status (Tagged out, damaged, grounded, etc.)	3/54=6 %	2/54=4 %	6/54=11 %	43/54=80 %
KV on at least one end	6/54=11 %	4/54=7 %	32/54=59 %	12/54=22 %
KV on both ends	2/55=4 %	5/55=9 %	29/55=53 %	19/55=35 %

Table 1.1-13 — Telemetry Data for Transmission Lines (100-230 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Respondents were asked to quantify telemetry data they receive ("all," "most," "some," or "none") for transmission lines (less than 100 kV) from areas adjacent to their areas of responsibility. Table 1.1-14 summarizes the responses. Most respondents received no telemetry data for transmission lines less than 100 kV in adjacent areas.

Type of Transmission-Line Telemetry Data	What Telemetry Data do You Receive for Transmission Lines (<100 kV) from Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
MW and Mvar flow on at least one end	0/55=0 %	2/55=4 %	24/55=44 %	29/55=53 %
MW and Mvar flow on both ends	0/55=0 %	1/55=2 %	17/55=31 %	37/55=67 %
Current flow magnitude (Amperes) at either end	0/53=0 %	0/53=0 %	4/53=8 %	49/53=92 %
Current flow phase angle (degrees) at either end	0/53=0 %	0/53=0 %	0/53=0 %	53/53=100 %
MVA flow at either end	0/53=0 %	0/53=0 %	2/53=4 %	51/53=96 %
Real-time operating limits determined by substation equipment/systems	0/54=0 %	1/54=2 %	2/54=4 %	51/54=94 %
Line connection status	1/55=2 %	2/55=4 %	20/55=36 %	32/55=58 %
Line availability status (Tagged out, damaged, grounded, etc.)	1/54=2 %	0/54=0 %	4/54=7 %	49/54=91 %
KV on at least one end	0/54=0 %	3/54=6 %	20/54=37 %	31/54=57 %
KV on both ends	0/54=0 %	0/54=0 %	19/54=35 %	35/54=65 %

Table 1.1-14 — Telemetry Data for Transmission Lines (less than 100 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Transmission-Line Data — Special or Calculated

The survey asked respondents to quantify telemetry data they receive ("all," "most," "some," or "none") for any special, real-time calculation for transmission lines in or adjacent to their areas of responsibility. Table 1.1-15 summarizes the responses. The majority of respondents do not receive special or calculated transmission-line telemetry data.

Special Transmission-Line Telemetry Data Type	Do You Use Any Special, Real-Time Calculation for Transmission Lines in or Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Special substitution for any values on lines not available by SCADA	7/55=13 %	1/55=2 %	19/55=35 %	28/55=51 %
Terminal angular separation (degrees)	2/53=4 %	0/53=0 %	4/53=8 %	47/53=89 %
Supplemental available data (such as line temperature, time in overload, etc)	1/52=2 %	2/52=4 %	5/52=10 %	44/52=85 %

Table 1.1-15 — Telemetry Data for Special, Real-Time Calculations for Transmission Lines In or Adjacent to Respondents' Areas of Responsibility

Transmission Transformer Telemetry Data

This subsection summarizes findings for transmission transformer telemetry data. All respondents have some form of transmission transformer telemetry data available; 85 percent rated the availability of transmission transformer telemetry data as "essential" for enhancing their situational awareness.

Transmission Transformer Data within Respondents' Areas of Responsibility

The survey asked respondents to quantify telemetry data they receive ("all," "most," "some," or "none") for transmission transformers (at various voltage levels) within their areas of responsibility. Table 1.1-16, Table 1.1-17, and Table 1.1-18 summarize the responses. It is interesting to note that the majority of respondents do not receive telemetry data for transmission transformers within their areas of responsibility even in the highest voltage range (i.e., 345-765 kV). As the voltage level decreases, even fewer telemetry data are received.

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (345-765 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Tap position	14/52=27 %	9/52=17 %	11/52=21 %	11/52=21 %
High-side MW and Mvars	21/53=40 %	9/53=17 %	14/53=26 %	9/53=17 %
High-side kV	27/53=51 %	9/53=17 %	10/53=19 %	7/53=13 %
Low-side MW and Mvars	21/53=40 %	12/53=23 %	13/53=25 %	7/53=13 %
Low-side kV	22/53=42 %	13/53=25 %	11/53=21 %	7/53=13 %
Oil temperature	7/51=14 %	4/51=8 %	12/51=24 %	28/51=55 %
Winding hot-spot temperatures	8/51=16 %	3/51=6 %	12/51=24 %	28/51=55 %
Ambient temperature	1/52=2 %	2/52=4 %	15/52=29 %	34/52=65 %
Cooling-system status	6/50=12 %	4/50=8 %	9/50=18 %	31/50=62 %
Combustible gas density	5/50=10 %	1/50=2 %	6/50=12 %	38/50=76 %
Real-time operating limits determined by substation equipment/systems	8/53=15 %	1/53=2 %	2/53=4 %	42/53=79 %
Voltage regulation control status	9/51=18 %	3/51=6 %	6/51=12 %	33/51=65 %

Table 1.1-16 — Telemetry Data for Transmission Transformers (345-765 kV) within Respondents' Areas of Responsibility

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (100-230 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Tap position	13/55=24 %	12/55=22 %	20/55=36 %	10/55=18 %
High-side MW and Mvars	16/57=28 %	15/57=26 %	21/57=37 %	5/57=9 %
High-side kV	23/57=40 %	20/57=35 %	12/57=21 %	2/57=4 %
Low-side MW and Mvars	22/57=39 %	17/57=30 %	17/57=30 %	1/57=2 %
Low-side kV	18/57=32 %	21/57=37 %	16/57=28 %	2/57=4 %
Oil temperature	4/55=7 %	5/55=9 %	13/55=24 %	33/55=60 %
Winding hot-spot temperatures	4/55=7 %	4/55=7 %	10/55=18 %	37/55=67 %
Ambient temperature	1/54=2 %	1/54=2 %	17/54=31 %	35/54=65 %
Cooling-system status	4/55=7 %	8/55=15 %	8/55=15 %	35/55=64 %
Combustible gas density	2/55=4 %	4/55=7 %	7/55=13 %	42/55=76 %
Real-time operating limits determined by substation equipment/systems	7/57=12 %	3/57=5 %	1/57=2 %	46/57=81 %
Voltage regulation control status	10/56=18 %	9/56=16 %	9/56=16 %	28/56=50 %

Table 1.1-17 — Telemetry Data for Transmission Transformers (100-230 kV) within Respondents' Areas of Responsibility

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (<100 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Tap position	4/54=7 %	6/54=11 %	21/54=39 %	23/54=43 %
High-side MW and Mvars	6/56=11 %	12/56=21 %	27/56=48 %	11/56=20 %
High-side kV	10/56=18 %	15/56=27 %	21/56=38 %	10/56=18 %
Low-side MW and Mvars	7/56=13 %	13/56=23 %	24/56=43 %	12/56=21 %
Low-side kV	7/56=13 %	15/56=27 %	22/56=39 %	12/56=21 %
Oil temperature	2/54=4 %	2/54=4 %	11/54=20 %	39/54=72 %
Winding hot-spot temperatures	2/54=4 %	2/54=4 %	11/54=20 %	39/54=72 %
Ambient temperature	0/54=0 %	2/54=4 %	8/54=15 %	44/54=81 %
Cooling-system status	1/55=2 %	2/55=4 %	9/55=16 %	43/55=78 %
Combustible gas density	1/53=2 %	2/53=4 %	6/53=11 %	44/53=83 %
Real-time operating limits determined by substation equipment/systems	4/55=7 %	1/55=2 %	2/55=4 %	2/55=4 %
Voltage regulation control status	5/54=9 %	7/54=13 %	6/54=11 %	36/54=67 %

Table 1.1-18 — Telemetry Data for Transmission Transformers (less than 100 kV) within Respondents' Areas of Responsibility

Transmission Transformer Data for Adjacent Areas

The respondents were asked to quantify telemetry data they receive ("all," "most," "some," or "none") for transmission transformers (at various voltage levels) from areas adjacent to their areas of responsibility. Table 1.1-19, Table 1.1-20, and Table 1.1-21 summarize the responses. The majority of respondents do not receive telemetry data for transmission transformers in adjacent areas.

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (345-765 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Tap position	0/53=0 %	4/53=8 %	7/53=13 %	42/53=79 %
High-side MW and Mvars	5/53=9 %	5/53=9 %	24/53=45 %	19/53=36 %
High-side kV	4/53=8 %	6/53=11 %	25/53=47 %	18/53=34 %
Low-side MW and Mvars	4/53=8 %	3/53=6 %	27/53=51 %	19/53=36 %
Low-side kV	5/53=9 %	2/53=4 %	27/53=51 %	19/53=36 %
Oil temperature	0/51=0 %	0/51=0 %	2/51=4 %	49/51=96 %
Winding hot-spot temperatures	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Ambient temperature	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Cooling-system status	0/52=0 %	0/52=0 %	2/52=4 %	50/52=96 %
Combustible gas density	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Real-time operating limits determined by substation equipment/systems	1/53=2 %	0/53=0 %	1/53=2 %	51/53=96 %
Voltage regulation control status	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %

Table 1.1-19 — Telemetry Data for Transmission Transformers (345-765 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (100-230 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Tap position	1/54=2 %	1/54=2 %	7/54=13 %	45/54=83 %
High-side MW and Mvars	2/55=4 %	5/55=9 %	24/55=44 %	24/55=44 %
High-side kV	2/55=4 %	6/55=11 %	25/55=45 %	22/55=40 %
Low-side MW and Mvars	2/54=4 %	5/54=9 %	24/54=44 %	23/54=43 %
Low-side kV	2/55=4 %	4/55=7 %	23/55=42 %	26/55=47 %
Oil temperature	0/53=0 %	0/53=0 %	2/53=4 %	51/53=96 %
Winding hot-spot temperatures	0/53=0 %	0/53=0 %	1/53=2 %	52/53=98 %
Ambient temperature	0/53=0 %	0/53=0 %	1/53=2 %	52/53=98 %
Cooling-system status	0/53=0 %	1/53=2 %	1/53=2 %	51/53=96 %
Combustible gas density	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Real-time operating limits determined by substation equipment/systems	0/54=0 %	1/54=2 %	1/54=2 %	52/54=96 %
Voltage regulation control status	0/53=0 %	0/53=0 %	2/53=4 %	51/53=96 %

Table 1.1-20 — Telemetry Data for Transmission Transformers (100-230 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Type of Transmission Transformer Telemetry Data	What Telemetry Data do You Receive for Transmission Transformers (<100 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Tap position	0/53=0 %	1/53=2 %	6/53=11 %	46/53=87 %
High-side MW and Mvars	0/54=0 %	4/54=7 %	15/54=28 %	35/54=65 %
High-side kV	0/54=0 %	5/54=9 %	14/54=26 %	35/54=65 %
Low-side MW and Mvars	0/54=0 %	5/54=9 %	14/54=26 %	35/54=65 %
Low-side kV	1/53=2 %	2/53=4 %	14/53=26 %	36/53=68 %
Oil temperature	0/52=0 %	0/52=0 %	2/52=4 %	50/52=96 %
Winding hot-spot temperatures	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Ambient temperature	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Cooling-system status	0/51=0 %	1/51=2 %	2/51=4 %	48/51=94 %
Combustible gas density	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %
Real-time operating limits determined by substation equipment/systems	0/53=0 %	1/53=2 %	0/53=0 %	52/53=98 %
Voltage regulation control status	0/52=0 %	0/52=0 %	1/52=2 %	51/52=98 %

Table 1.1-21 — Telemetry Data for Transmission Transformers (100-230 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Substation Switching Device Telemetry Data

This subsection summarizes findings for substation switching device telemetry data. These data are gathered from substation circuit breakers and disconnect switches. All survey respondents have some form of substation switching device telemetry data available; 93 percent rate the availability of substation switching device data "essential" for enhancing their situational awareness.

Substation Switching Device Data within Respondents' Areas of Responsibility

Respondents were asked to quantify the telemetry data they receive ("all," "most," "some," or "none") for substation circuit breakers and disconnect switches (at various voltage levels) within their areas of responsibility. Table 1.1-22, Table 1.1-23, and Table 1.1-24 summarize the responses. Substation circuit breaker status data are the most commonly received.

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (345-765 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	41/51=80 %	4/51=8 %	0/51=0 %	6/51=12 %
Breaker disconnect switch status	11/51=22 %	9/51=18 %	14/51=27 %	17/51=33 %
Bus tie switch status	15/50=30 %	13/50=26 %	9/50=18 %	13/50=26 %
Bypass switch status	13/50=26 %	7/50=14 %	6/50=12 %	24/50=48 %
Transformer disconnect switch status	15/51=29 %	13/51=25 %	9/51=18 %	14/51=27 %
Line disconnect switch status	16/50=32 %	11/50=22 %	7/50=14 %	16/50=32 %
Reactor/Capacitor bank disconnect switch status	19/51=37 %	11/51=22 %	7/51=14 %	14/51=27 %

Table 1.1-22 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (345-765 kV) within Respondents' Areas of Responsibility

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (100-230 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	42/56=75 %	11/56=20 %	3/56=5 %	0/56=0 %
Breaker disconnect switch status	9/56=16 %	7/56=13 %	24/56=43 %	16/56=29 %
Bus tie switch status	14/55=25 %	14/55=25 %	14/55=25 %	13/55=24 %
Bypass switch status	9/55=16 %	9/55=16 %	11/55=20 %	26/55=47 %
Transformer disconnect switch status	10/54=19 %	15/54=28 %	15/54=28 %	15/54=28 %
Line disconnect switch status	9/55=16 %	13/55=24 %	20/55=36 %	13/55=24 %
Reactor/Capacitor bank disconnect switch status	16/56=29 %	15/56=27 %	13/56=23 %	12/56=21 %

Table 1.1-23 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (100-230 kV) within Respondents' Areas of Responsibility

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (< 100 kV) Within Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	42/56=75 %	11/56=20 %	3/56=5 %	0/56=0 %
Breaker disconnect switch status	9/56=16 %	7/56=13 %	24/56=43 %	16/56=29 %
Bus tie switch status	14/55=25 %	14/55=25 %	14/55=25 %	13/55=24 %
Bypass switch status	9/55=16 %	9/55=16 %	11/55=20 %	26/55=47 %
Transformer disconnect switch status	10/54=19 %	15/54=28 %	15/54=28 %	15/54=28 %
Line disconnect switch status	9/55=16 %	13/55=24 %	20/55=36 %	13/55=24 %
Reactor/Capacitor bank disconnect switch status	16/56=29 %	15/56=27 %	13/56=23 %	12/56=21 %

Table 1.1-24 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (< 100 kV) within Respondents' Areas of Responsibility

Substation Switching Device Data for Adjacent Areas

The survey asked respondents to quantify telemetry data they receive ("all," "most," "some," or "none") for substation circuit breakers and disconnect switches (at various voltage levels) from areas adjacent to their areas of responsibility. Table 1.1-25, Table 1.1-26, and Table 1.1-27 summarize the responses. The majority of respondents do not receive telemetry data for substation switching devices in adjacent areas.

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (345-765 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	7/53=13 %	7/53=13 %	27/53=51 %	12/53=23 %
Breaker disconnect switch status	1/52=2 %	4/52=8 %	13/52=25 %	34/52=65 %
Bus tie switch status	3/52=6 %	2/52=4 %	15/52=29 %	32/52=62 %
Bypass switch status	2/51=4 %	2/51=4 %	11/51=22 %	36/51=71 %
Transformer disconnect switch status	2/52=4 %	4/52=8 %	13/52=25 %	33/52=63 %
Line disconnect switch status	2/52=4 %	3/52=6 %	15/52=29 %	32/52=62 %
Reactor/Capacitor bank disconnect switch status	3/52=6 %	3/52=6 %	19/52=37 %	27/52=52 %

Table 1.1-25 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (345-765 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (100-230 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	5/54=9 %	4/54=7 %	38/54=70 %	7/54=13 %
Breaker disconnect switch status	0/53=0 %	1/53=2 %	13/53=25 %	39/53=74 %
Bus tie switch status	1/53=2 %	2/53=4 %	19/53=36 %	31/53=58 %
Bypass switch status	0/53=0 %	2/53=4 %	12/53=23 %	39/53=74 %
Transformer disconnect switch status	1/53=2 %	3/53=6 %	18/53=34 %	31/53=58 %
Line disconnect switch status	1/53=2 %	1/53=2 %	19/53=36 %	32/53=60 %
Reactor/Capacitor bank disconnect switch status	1/53=2 %	2/53=4 %	21/53=40 %	29/53=55 %

Table 1.1-26 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (100-230 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Type of Substation Switching Device Telemetry Data	What Telemetry Data do You Receive for Substation Switching Devices (< 100 kV) in Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
Circuit breaker status	2/52=4 %	2/52=4 %	21/52=40 %	27/52=52 %
Breaker disconnect switch status	0/51=0 %	0/51=0 %	6/51=12 %	45/51=88 %
Bus tie switch status	0/51=0 %	0/51=0 %	8/51=16 %	43/51=84 %
Bypass switch status	0/50=0 %	0/50=0 %	8/50=16 %	42/50=84 %
Transformer disconnect switch status	1/51=2 %	0/51=0 %	11/51=22 %	39/51=76 %
Line disconnect switch status	1/51=2 %	0/51=0 %	10/51=20 %	40/51=78 %
Reactor/Capacitor bank disconnect switch status	1/51=2 %	0/51=0 %	11/51=22 %	39/51=76 %

Table 1.1-27 — Telemetry Data for Substation Circuit Breakers and Disconnect Switches (< 100 kV) from Areas Adjacent to Respondents' Areas of Responsibility

Telemetry Data Maintenance and Support Practices

The Real-Time Tools Survey includes questions pertaining to routine, regular activities that ensure the quality and integrity of telemetered data. A majority of respondents (66 percent) perform maintenance activities related to the availability of their telemetry data. Respondents that have some form of maintenance activity consider it to be "essential" (56 percent) or "desirable" (42 percent) for situational awareness. A majority (78 percent) of respondents that perform maintenance have processes or procedures for telemetry personnel to perform regular, manual checks of the data. A majority (78 percent) of the respondents perform maintenance activities "as needed."

Fifty percent or more of respondents who use testing/debugging/diagnostic tools to check telemetry data employ the following tools:

- Remote terminal unit (RTU) test set (RTU simulator)
- Data communication network analyzer
- EMS host communication traffic viewer/analyzer
- Communication error reporting on EMS
- Quality code processing
- On-line diagnostics (running in real time)

The survey includes questions about tools/processes to make support personnel aware when telemetered data are erroneous or not available. A majority of respondents (94 percent) notify the personnel responsible for the telemetered data if the data are erroneous or are not received. A majority (78 percent) consider these notifications "essential" for situational awareness. The most common notification method is an alarm; the operator receiving the alarm calls support personnel to address the problem. Respondents also have provisions for personnel to remotely support operators when telemetry data issues arise.

Recommendations for New Reliability Standards

Telemetry data are essential for operators to monitor the status of bulk electric system elements and parameters. Telemetry data are typically the main input to other applications/tools (i.e., SCADA applications, alarm tools, state estimator) used to monitor bulk electric system elements and parameters. The following discussions support RTBPTF's major recommendation to make telemetry data systems mandatory (see the Reliability Toolbox Recommendation and Rationale section, which describes the recommended mandatory tools, including telemetry data systems, for RCs and TOPs).

RTBPTF also recognizes that entities cannot be expected to use specific tools to monitor the bulk electric system without stipulating which components of the system are to be monitored or require telemetry data, so the following subsections discuss this issue. Where appropriate, RTBPTF recommends modifications to existing standards.

Recommendation – S1

Mandate the following reliability tools as mandatory monitoring and analysis tools

- Alarm Tools
- Telemetry Data Systems
- Network Topology Processor
- State Estimator
- Contingency Analysis

Telemetry data systems: mandatory monitoring and analysis tool

Telemetry data systems update status and analog values from conventional SCADA/EMSs and from the SCADA/EMSs of others (via ICCP, ISN, etc.) continuously in real or near-real time. Telemetry data systems are the primary sources of information that directly and indirectly (by supporting other applications) provide situational awareness to operators. RTBPTF believes that telemetry data systems are essential for operators to monitor and maintain the reliability of the bulk electric system. Existing NERC reliability standards implicitly assume the use of telemetry data systems to aid RCs and TOPs in maintaining situational awareness for the bulk electric system. Specifying telemetry data systems as part of the Reliability Toolbox[4] eliminates the vagueness in the current NERC reliability standards and clarifies that telemetry data systems, as defined, are mandatory.

Telemetry data system availability

Because RTBPTF recommends that telemetry data systems be mandatory tools for maintaining bulk electric system situational awareness, these tools must be highly redundant and available. Thus, RTBPTF also recommends requiring that operators be aware of the availability status of these tools. RTBPTF recommendation presented in Section 5.4, Critical Applications Monitoring, addresses telemetry data system availability. RTBPTF believes that the recommendations in Section 5.4 are sufficient to maintain operators' situational awareness of the availability of this critical monitoring tool.

"Bulk Electric System" definition

The term "bulk electric system" appears throughout numerous existing NERC reliability standards. The NERC Glossary defines "bulk electric system" as follows: "[a]s defined by the Regional Reliability Organization, the electrical generation of resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages 100 kV or higher. Radial transmission facilities serving only load with one transmission

[4] See the Reliability Toolbox Recommendation and Rationale section.

source are generally not included in this definition." However, section 215(a)(1) of the Federal Powers Act defines the bulk power system as "[f]acilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy."

The *FERC Staff Assessment*[5] notes that "[t]he FPA and NERC definitions obviously differ. The standards currently are applied only to the Bulk Electric System as defined by each Region. However, section 215(a)(3) of the FPA defines Reliability Standard as a requirement approved by the Commission to provide for reliable operation of the Bulk-Power System. The term Bulk Electric System does not appear to include all the system components from all non-distribution voltage levels, control systems, and electric energy from all generating facilities needed to maintain transmission system reliability included in the definition of Bulk-Power System."

The *FERC Staff Assessment* states, "[e]lements of numerous standards appear to be subject to multiple interpretations, especially with regard to the specificity of the standards' requirements, measurability, and degrees of compliance. This ambiguity also extends to the differing definitions for the Bulk-Power System and the Bulk Electric System." The *FERC Staff Assessment* further notes, "[w]hen the task of defining the Bulk Electric System is delegated to each RRO, the result could be conflicting multiple definitions that subject different facilities to, or exclude different facilities from, the requirements of the standards."

Recommendation – I1

Define what constitutes bulk electric system elements and parameters as they relate to existing standards.

RTBPTF Recommendation

RTBPTF recommends that NERC define what constitutes bulk electric system elements and parameters as they relate to existing standards. Specifically, NERC needs to resolve whether the bulk electric system should continue to be defined by regional reliability organizations (RROs) or whether a single NERC definition should be adopted. In either case, the defined criteria shall be applied to all of the NERC reliability standards. The criteria for classifying bulk electric system elements and parameters need to be clearly and unambiguously stated

[5] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

so that reliability entities can comply fully with reliability standards that refer to the bulk electric system.

Rationale

The bulk electric system definition is particularly important for numerous existing NERC standards that specify and require "monitoring" by reliability entities of specific data and bulk electric system elements and parameters. The standards have common, well-established requirements but, in most cases, are not specific about how reliability entities are to measure and/or comply with the monitoring requirements.

The survey results quantified the number of telemetry data currently available for elements at different voltage levels (100 kV and above). Not all telemetry data for these elements are currently available. This is an interesting finding because the 100-kV level is explicitly identified in the current definition of the bulk electric system. The survey results illustrate that respondents' telemetry data practices are not uniform. The results also suggest that design standards (related to telemetry measurements for transmission facilities) are typically developed by transmission operators for their own use. These practices and standards do not appear to be completely supportive of NERC-mandated requirements for monitoring of the bulk electric system elements by reliability entities.

Monitoring standards/requirements

The existing NERC standards listed below require that reliability entities monitor bulk electric system elements and parameters. In RTBPTF's opinion, the word "monitor" does not imply viewing large amounts of raw telemetered data but rather viewing data in a manner and format that allows operators to rapidly judge the state of the bulk electric system and take corrective action when necessary. Reliability entities could monitor bulk electric system elements and parameters directly using tools such as state estimators (with defined measurement-observability requirements) or other indirect approaches such as calculated points based on existing telemetry data (i.e., calculated MVA based on MW and Mvar telemetered data). However, all such monitoring approaches depend on information obtained from processing raw data. Processing is necessary to use telemetry data for monitoring; this understanding forms the context for the discussions of monitoring standards below.

Where noted below, RTBPTF recommends additions/modifications to standards and their corresponding requirements and/or measures. The discussion emphasizes use of available tools to aid reliability entities in monitoring bulk electric system elements and parameters. The recommendations below assume that the definition of the term "bulk electric system" is clarified per the RTBPTF recommendation above.

1. NERC Reliability Standard TOP-005, Operational Reliability Information

The purpose of TOP-005 is "[t]o ensure reliability entities have the operating data needed to monitor system conditions within their areas." This standard specifies what data are needed by reliability entities to monitor the bulk power system. Requirement R1 states, "[e]ach Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area… [e]ach Reliability Coordinator shall identify the data requirements from the list [specified] in [the]…'Electric System Reliability Data' and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area."

RTBPTF Recommendations

The use of telemetry data systems is ubiquitous in the industry. Moreover, improvements in data communication technologies have dramatically increased the update frequency that is now common to all systems. The "Electric System Reliability Data" appendix[6] specifies the data required from each RC's TOPs and BAs to perform operational reliability assessments and to coordinate reliable operations within the RC's area. The "Electric System Reliability Data" appendix also lists the types of data that RCs, TOPs, and BAs are expected to provide to and share with each other.

In general, RTBPTF believes that the update frequency for certain types of reliability data specified in the "Electric System Reliability Data" appendix of at least every 10 minutes is not sufficient to monitor critical reliability parameters in real time. RTBPTF recommends changing the update frequency requirement to every 10 seconds. RTBPTF believes that most commercially available telemetry data systems used industry-wide are capable of supporting a 10-second update frequency.

The specific recommendations for modifications to the items listed in the "Electric System Reliability Data" appendix are explained in Table 1.1-28 (see "Discussion" column).

Rationale

Table 1.1-28 lists the contents of the "Electric System Reliability Data" appendix; the "Discussion" column contains RTBPTF's recommendations for modifications to items listed in the appendix together with the corresponding rationale.

[6] This is an appendix to Standard TOP-005.

<table>
<tr><th>Type of Reliability Data</th><th>Discussion</th></tr>
<tr><td>1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:
1.1.1 Status
1.1.2 MW or ampere loadings
1.1.3 MVA capability
1.1.4 Transformer tap and phase angle settings
1.1.5 Key voltages</td><td><u>Recommendations:</u>
1. RTBPTF recommends revising item 1.1.2 “MW or ampere loadings” to read: “MW, Mvar, and ampere loadings.”
2. RTBPTF recommends that the following transmission data specified in item 1.1 of the “Electric System Reliability Data” appendix (with the exception of MVA capability data) shall be provided and updated at least every 10 seconds:
• Status
• MW or ampere loadings
• Transformer tap and phase angle settings
• Key voltages
3. RTBPTF recommends that MVA capability data shall be “provided upon every update” or “as soon as available.”
<u>Rationale:</u>
1. For completeness, the “Mvar loadings” for transmission data should be part of item 1.1.2 of the “Electric Systems Reliability Data” appendix. Mvar data are essential to ascertain proper loadings of transmission equipment.
2. RTBPTF believes that an update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current data to monitor critical reliability parameters in real time. Transmission data may be needed by other applications such as the state estimator and/or contingency analysis to detect actual or potential SOL/IROL violations. More frequent updates of transmission data are needed to provide better analysis for operators.
3. RTBPTF believes that the MVA capability data (and the corresponding update frequency for the data) are addressed by Standard TOP-002, Requirement 11, which states, “[t]he Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs… The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.” It is not necessary to provide the MVA capability information unless new updates are available.</td></tr>
</table>

Type of Reliability Data	Discussion
1.2. Generator data 1.2.1 Status 1.2.2 MW and Mvar capability 1.2.3 MW and Mvar net output 1.2.4 Status of automatic voltage control facilities	Recommendations: 1. RTBPTF recommends that the following generator data specified in item 1.2 of the "Electric System Reliability Data" appendix (with the exception of MW and Mvar capability data) shall be provided and updated at least every 10 seconds: • Status • MW and Mvar net output • Status of automatic voltage control facilities 2. RTBPTF recommends that MW and Mvar capability data shall be "provided upon every update" or "as soon as available." Rationale: 1. RTBPTF believes that update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current data to monitor critical reliability parameters in real time. Generator data may be needed by other applications such as the state estimator and/or contingency analysis to detect actual or potential SOL/IROL violations. More frequent update of generator data is needed to provide better analysis for operators. 2. The generator MW and Mvar capability data (and the corresponding update frequency for the data) are addressed by Standard TOP-002, Requirement 11, which states, "[t]he Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs… The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions [i.e., generator capability]; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator." It is not necessary to provide the generator MW and Mvar capability information unless new updates are available.
1.3. Operating reserve 1.3.1 MW reserve available within ten minutes	Recommendation: 1. RTBPTF recommends that the generator data specified in item 1.3 of the "Electric System Reliability Data" appendix shall be provided at least every 10 seconds. Rationale: 1. RTBPTF believes that update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current data to monitor critical reliability parameters (i.e., operating reserves) in real time.

Type of Reliability Data	Discussion
1.4. Balancing Authority demand 1.4.1 Instantaneous	Recommendation: 1. RTBPTF recommends that the balancing authority demand data specified in item 1.4 of the "Electric System Reliability Data" appendix shall be provided at least every 10 seconds. Rationale: 1. RTBPTF believes that update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current operating data to monitor critical reliability parameters (i.e., instantaneous BA demand) in real time.
1.5. Interchange 1.5.1 Instantaneous actual interchange with each Balancing Authority 1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities 1.5.3 Interchange Schedules for the next 24 hours	Recommendations: 1. RTBPTF recommends that the interchange data specified in item 1.5 (with the exception of interchange schedules for the next 24 hours) of the "Electric System Reliability Data" appendix shall be provided at least every 10 seconds. 2. The interchange schedules for the next 24 hours shall be provided with every schedule update. Rationale: 1. RTBPTF believes that update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current operating data to monitor critical reliability parameters (i.e., instantaneous actual interchange with each BA and Current Interchange Schedules with each BA by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities) in real time. 2. RTBPTF believes that it is sufficient to provide interchange schedules for the next 24 hours when new updates are available, i.e., when schedules are changed.
1.6. Area Control Error and frequency 1.6.1 Instantaneous area control error 1.6.2 Clock hour area control error 1.6.3 System frequency at one or more locations in the Balancing Authority	Recommendations: 1. RTBPTF recommends that the area control error (ACE) and frequency data specified in item 1.6 (with the exception of clock-hour ACE) of the "Electric System Reliability Data" appendix shall be provided at least every 10 seconds. 2. RTBPTF recommends that the clock-hour ACE shall be provided with every hourly update. Rationale: 1. RTBPTF believes that update frequency of at least every 10 minutes is not sufficient for responsible entities to have the most current operating data to monitor critical reliability parameters (ACE and frequency data) in real time. 2. The clock-hour area control error does not need to be updated every 10 seconds; an hourly update of the data is sufficient.

Type of Reliability Data	Discussion
2. Other operating information updated as soon as available 2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect 2.2. Forecast of operating reserve at peak, and time of peak for current day and next day 2.3. Forecast peak demand for current day and next day 2.4. Forecast changes in equipment status 2.5. New facilities in place. 2.6. New or degraded special protection systems 2.7. Emergency operating procedures in effect 2.8. Severe weather, fire, or earthquake 2.9. Multi-site sabotage	Recommendation: 1. RTBPTF recommends that an additional item (i.e., Status of Special Protection Systems) be added to item 2 in this list. Rationale: 1. Standard IRO-005 (Requirement R1) states "[e]ach Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following…R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading." For completeness, the status of Special Protection Schemes should be included in this list.

Table 1.1-28 — Electric System Reliability Data (TOP-005, Requirement R1, Attachment 1) and RTBPTF Recommendations

3. NERC Reliability Standard IRO-002, Reliability Coordination – Facilities

RCs need information, tools, and other capabilities to perform their responsibilities. Requirement R5 of IRO-002 states "[e]ach Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure."

Requirement R6 states "[e]ach Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area."

In context, the standards quoted above do not specify which bulk electric system elements need to be telemetered. Entities cannot be expected to use "information, tools, and other capabilities" without a clear understanding of the components of the system that need to be monitored or require telemetry data.

Recommendation – S2

Compile and maintain a list of all bulk electric system elements within RC's area of responsibility.

RTBPTF Recommendations

Once the bulk electric system definition is clarified, per the recommendation above, RTBPTF recommends that a new requirement be established under the current Standard IRO-002 (Reliability Coordination — Facilities) that shall apply to RCs and specify which bulk electric system elements need to be telemetered. The following requirement is recommended.[7]

PR1. Each reliability coordinator shall develop and maintain a list (the "Bulk Electric System Elements List") of specific bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) within its reliability coordinator area. The regional reliability organizations shall oversee this process within their regions. For consistency, this list shall be based upon the "Electric System Reliability Data" specified in Standard TOP-005. The Bulk Electric System Elements List shall contain the bulk electric system elements (within the reliability coordinator's area) necessary to allow identification of potential or actual SOL/IROL violations.

PR1.1. Each reliability coordinator shall specify the monitoring methodology for each item on its Bulk Electric System Elements List (i.e., whether monitoring by direct or indirect methods).

PR1.2. For bulk electric system elements to be monitored directly, each reliability coordinator shall also specify the characteristics for specific data types (i.e., MW, kV, breaker status, etc.) that shall be telemetered for specific facilities (i.e., transmission lines, transformers, generators, etc.) at specific voltage levels (i.e., 765 kV, 500 kV, etc.). The telemetry data characteristics shall include, but not be limited to, the following characteristics: update frequency (whether periodic or by exception), latency characteristics, and quality codes.

PR1.3. Each reliability coordinator shall telemeter items listed in the Bulk Electric System Elements List (generators, transmission lines, buses, transformers, breakers, etc.) for which a direct monitoring methodology is specified and shall provide information that can be easily

[7] Proposed requirements are designated "PR," and proposed measures are designated "PM."

understood and interpreted by the reliability coordinator's operations personnel. Update frequency shall conform to the "Electric System Reliability Data" list as specified[8] in Standard TOP-005 for each data type.

RTBPTF recommends the following measure for the requirement stated above:

PM1. The reliability coordinator shall maintain the "Bulk Electric System Elements List" document as stated in Requirement PR1.

Rationale

RTBPTF believes that a requirement specifying a methodology for documenting the bulk electric system elements for which telemetering is required within an RC area removes any vagueness regarding what data must be provided (and by what methodology and update frequency) by reliability entities within the RC area. The recommendation above formalizes a process for RCs to document which bulk electric system elements they need to monitor and telemeter within their RC area.

4. *NERC Reliability Standard IRO-005, Reliability Coordination — Current-Day Operations*

Standard IRO-005 states that "[t]he Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas."

Requirement R1 states "each reliability coordinator shall monitor its reliability coordinator area parameters, including but not limited to:[9]

- R1.1. Current status of bulk electric system elements (transmission or generation including critical auxiliaries such as automatic voltage regulators and special protection systems) and system loading;
- R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, and including the plan's viability and scope;
- R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, and including the plan's viability and scope;
- R1.4. System real and reactive reserves (actual versus required);
- R1.5. Capacity and energy adequacy conditions;
- R1.6. Current ACE for all of its balancing authorities;

[8] Take note that the RTBPTF recommends changes to the "Electric System Reliability Data".
[9] The numbering scheme for these requirements were adapted to the current numbering scheme in the current version of Standard IRO-005.

R1.7. Current local or transmission loading relief procedures in effect;
R1.8. Planned generation dispatches;
R1.9. Planned transmission or generation outages; and
R1.10. Contingency events

For each of the requirements stated above for Standard IRO-005 (Requirement R1), no measures are currently specified. Requirement R1 mandates that each RC monitor its RC area parameters. Although the requirement is specific as to the parameters that need to be monitored, it does not specify any compliance measures.

Recommendation – S3

Add new requirements and measures pertaining to RC monitoring of the bulk electric system.

RTBPTF Recommendations

In general, the survey results support the availability of telemetry data for the RC area parameters mentioned in Standard IRO-005 (Requirement R1). As discussed previously, it is difficult to recommend measures for Standard IRO-005 (Requirement R1) without resolving the definition of the term "bulk electric system." Once the bulk electric system definition is clarified, RTBPTF recommends the following measures[10] for Standard IRO-005 (Requirements R1)[11].

PM1. The following are measures for each of the requirements R1.1-R1.6, and R1.10:

PM1.1. The reliability coordinator's Bulk Electric System List (as required in Standard IRO-002)[12] shall contain the status of bulk electric system elements (transmission or generation including critical auxiliaries such as automatic voltage regulators and special protection systems) and system loading necessary for the reliability coordinator to monitor its reliability coordinator area parameters. The reliability coordinator shall demonstrate, on request, that the reliability coordinator is monitoring every item listed in the Bulk Electric System Elements List.
In addition to the reliability coordinator's Bulk Electric System List, the reliability coordinator shall also

[10] The numbering scheme for these proposed measures (PM) coincides with the existing requirements – i.e., the proposed measure for Requirement R1.1 is numbered PM1.1.
[11] RTBPTF omitted any recommendations for measures related to Standard IRO-005 (Requirements R1.7-R.9) because they are not within RTBPTF's scope; these reliability coordinator parameters do not involve telemetry data or other tools discussed in this report.
[12] See recommendations for Standard IRO-002 above.

demonstrate the monitoring of bulk electric system elements (transmission or generation including critical auxiliaries such as automatic voltage regulators and special protection systems) and system loading necessary for the reliability coordinator to monitor its reliability coordinator area parameters within its wide area.

PM1.2. The reliability coordinator shall demonstrate the monitoring of current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, and including the plan's viability and scope by having a display showing the contingency analysis base-case solution available to the reliability coordinator. The display shall show current pre-contingency element conditions within the reliability coordinator's wide area.

PM1.3. The reliability coordinator shall demonstrate the monitoring of current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, and including the plan's viability and scope by having a display showing the contingency analysis solution for each defined contingency available to the reliability coordinator. The display shall show current post-contingency element conditions within the reliability coordinator's wide area.

PM1.4. The reliability coordinator shall demonstrate the monitoring of system real and reactive reserves (actual versus required) by having displays (or visualization tools) showing the real-time information related to system real and reactive reserves[13] (actual versus required) available to the reliability coordinator. The displays (or visualization tools) shall show information on system real and reactive reserves (actual versus required) within the reliability coordinator's wide area.

PM1.5. The reliability coordinator shall demonstrate the monitoring of capacity and energy adequacy conditions by having displays (or visualization tools) showing the real-time information related to capacity and energy adequacy conditions available to the reliability coordinator. The displays (or visualization tools) shall show information on capacity and energy adequacy conditions within the reliability coordinator's wide area.

[13] Note that one of the major issues that RTBPTF identifies in this report (see the Introduction) as needing resolution from NERC and the industry is the specification of what constitutes acceptable reactive reserves.

PM1.6. The reliability coordinator shall demonstrate the monitoring of the current ACE for all of its balancing authorities by having displays (or visualization tools) showing the real-time ACE for all of its balancing authorities available to the reliability coordinator.

PM1.7. The reliability coordinator shall demonstrate the monitoring contingency events by having displays (or visualization tools) showing time-stamped contingency events available to the reliability coordinator. The displays (or visualization tools) shall show contingency events data/information within the reliability coordinator's wide area.

Rationale

For the proposed measure PM1.1, RTBPTF interprets the "current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading" as stated in Standard IRO-005 (Requirement R1.1) as referring to some of the items contained in the Bulk Electric System Elements List; RTBPTF recommends the Bulk Electric System Elements List above as a new requirement in Standard IRO-002. Relating the measure for Standard IRO-005 (Requirement R1.1) to the Bulk Electric System Elements List provides a direct way to document what is being monitored by reliability coordinators.

For the proposed measures PM1.2 and PM1.3, RTBPTF believes that having the contingency analysis base-case solution and contingency analysis solution for each defined contingency available to the RC sufficiently demonstrates the monitoring of "current pre- and post-contingency element conditions." Telemetry data indirectly support the contingency analysis application output/solution. Section 2.6 of this report, Contingency Analysis, discusses recommendations for contingency analysis.

For proposed measure PM1.4, RTBPTF interprets "system real and reactive reserves (actual versus required)" as the output of the reactive reserve monitor (a type of visualization tool). This application monitors reactive reserves (static and dynamic) in local geographic areas or major load centers and can send an alarm to the operator when a unit in the area reaches its reactive capability or the minimum reactive reserve requirement for the area is approached. Telemetry data indirectly support the reactive reserve monitor output/solution. Section 2.2 of this report, Visualization Techniques, discusses recommendations for visualization tools.

For proposed measure PM1.5, RTBPTF interprets "capacity and energy adequacy conditions" as the output of the capacity assessment application.[14] The capacity assessment application gives an overview of available generation capacity (MW or Mvar) in real time. Telemetry data indirectly support the capacity assessment application output/solution. Section 2.12 of this report, Capacity Assessment, discusses recommendations for the capacity assessment application.

For proposed measure PM1.6, RTBPTF believes that the current ACE for all of an RC's BAs could be obtained as ICCP-specific data from the BAs. Each RC could demonstrate compliance by showing the monitoring (through ICCP data exchange or direct telemetry methods) of the current ACE for all the RC's BAs. A summary display showing the ACE for all of an RC's BAs provides a measure for Standard IRO-005 (Requirement R1.6). Standard TOP-005 also requires current ACE data.

For proposed measure PM1.10, RTBPTF believes that a contingency event could result from the change in status of a single or a combination of multiple bulk electric system elements. For example, when a 230-kV transmission line contingency event occurs, it could be the result of all of the transmission circuit breakers related to the 230-kV transmission line having a change of status to "open." A summary display showing the contingency events provides a measure for Standard IRO-005 (Requirement R1.10). This summary display could also be the output of the alarm tool that selectively lists all of the contingency events for the RC wide area.

5. NERC Reliability Standard PRC-001, System Protection Coordination
The purpose of Standard PRC-001 is "to ensure system protection is coordinated among operating entities." Requirement R6 mandates that "[e]ach 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."

Standard PRC-001 (Requirement R6) is the same as Standard IRO-005 (Requirement 1.1) as related to special protection schemes. Standard PRC-001 applies to TOPs and BAs; Standard IRO-005 applies to RCs.

There are currently no specified measures for Standard PRC-001 (Requirement R6).

[14] An equivalent application could be substituted for a capacity assessment application as long as the data and displays (or visualization tools) show the "capacity and energy adequacy conditions."

RTBPTF Recommendation

In PRC-001 (Requirement R6), RTBPTF interprets “monitor” to mean that special protection system (SPS) status needs to be provided via telemetry or another real-time method. Telemetry is the most direct and current method for monitoring special monitoring systems. RTBPTF recommends that PRC-001 (Requirement R6) be modified to the following:

PR1. Each transmission operator and balancing authority shall monitor the status of each special protection system (SPS) in the transmission operator’s or balancing authority’s area via telemetry or another real-time method, and shall notify affected transmission operators and balancing authorities of each change in status. Each transmission operator and balancing authority shall also notify the host reliability coordinator via the use of telemetry data systems of each change in status.

RTBPTF recommends the following measure for the requirement stated above:

PM1. Each transmission operator and balancing authority shall demonstrate the monitoring the status of each special protection system (SPS) in the transmission operator’s or balancing authority’s area by having displays (or visualization tools) showing the real-time information related to the status of each special protection system (SPS) in the transmission operator’s or balancing authority’s area.

Rationale

RTBPTF interprets the monitoring of “the status of each Special Protection System” as the output of the remedial action scheme (RAS) tool (a subset of visualization tools discussed in Section 2.2, Visualization Techniques). The RAS allows users to: monitor the status of critical power system parameters, measure the proximity of these parameters to the triggering conditions for special protection schemes or total system failure, and alarm operators and advise them of actions required to mitigate pending problems. Telemetry data indirectly support the RAS application output/solution. Section 2.2, Visualization Techniques, of this report discusses the recommendations for visualization tools (including RAS). In addition, RTBPTF has recommended adding monitoring of the status of SPSs as part of the ‘Electric System Reliability Data’ appendix (see recommendations for Standard TOP-005).

6. NERC Reliability Standard TOP-006, Monitoring System Conditions

The purpose of Standard TOP-006 is “to ensure critical reliability parameters are monitored in real-time.” Standard TOP-006 specifies the critical system parameters to be monitored by responsible entities. The requirements for Standard TOP-006[15] are listed below:

- R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.
  - R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.
  - R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.
- R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.
- R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.
- R4. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.
- R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.
- R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.
- R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.

The *FERC Staff Assessment* states: "[t]he standard does not have any Compliance Measures and Levels of Noncompliance and without such specificity, the ERO will not have norms that are specific enough to implement consistent and effective enforcement." On the topic of real-time monitoring in Standard TOP-006,[16] The *FERC Staff Assessment* states: "while the requirements identify the data to be gathered, they fail to describe the tools necessary to turn that data into critical reliability parameters, i.e., system capability or contingency analysis, which are required to achieve situational awareness. Reliability Coordinators, Transmission Operators, and Balancing

[15] These requirements are listed verbatim from Standard TOP-006.
[16] "To ensure critical reliability parameters are monitored in real-time."

Authorities must be aware of the status of their respective systems, and such situational awareness cannot be obtained by viewing massive amounts of raw data. The standard does not contain any Measures to assess compliance with Requirements or Levels of Non-Compliance required for enforcement."

RTBPTF Recommendation

RTBPTF interprets "critical reliability parameters" as outputs of some of the tools/applications described throughout this report and through the use of the displays (or visualization tools) for each respective tool/application. The tools/applications described throughout this report turn raw data (most of which are telemetry data) into "critical reliability parameters." RTBPTF recommends measures for the existing requirements within Standard TOP-006 that applicable entities demonstrate actual usage of such tools/applications pertinent to each requirement. RTBPTF recommends the following measures[17] for Standard TOP-006.

PM1. Each transmission operator and balancing authority shall demonstrate the knowledge of the status of all generation resources available for use by having displays (or visualization tools) showing the following:

- PM1.1. A summary display showing the host balancing authority information of all generation resources available for use, obtained from the balancing authority area generator operators. This summary display shall be the output of the host balancing authority's capacity assessment (or equivalent) application.
- PM1.2. The data from the summary display as stated in PM1.1 shall be shared with affected transmission operators and the reliability coordinator.

PM2. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate the capability of monitoring of applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources by having displays (or visualization tools) showing the output of the reliability entity's telemetry data systems.

PM3. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate the capability of providing appropriate technical information concerning protective relays to their operating personnel by having these documents (through paper copies or electronic documentation) readily available for their operating personnel.

PM4. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate having the capability of obtaining

[17] The numbering scheme for these proposed measures (PM) coincides with the existing requirements (i.e., the proposed measure for Requirement R1 in numbered PM1).

information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern by having displays (or visualization tools) showing the output of the reliability entity's historical/real-time/forecast weather systems as well the output of the reliability entity's near-term load forecast systems.

PM5. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate the use of monitoring equipment (such as telemetry data systems and/or alarm tools) to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

PM6. Each balancing authority and transmission operator shall demonstrate the use of sufficient metering with suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations by requiring the reliability entity to demonstrate the usage of telemetry data systems and/or alarm tools sufficient to support the update frequency specified by Standard TOP-005, "Electric System Reliability Data" appendix.

PM7. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate the capability monitoring of system frequency by having displays (or visualization tools) showing real-time and current system frequency information.

Rationale

In general, the discussions below work in conjunction with RTBPTF's above recommendations for Standard IRO-002 and recommendations for modifications to the update frequency as mandated by Standard TOP-005. For each "critical reliability parameter," a specific tool(s)/application(s) is(are) suggested as a method to measure the usage of monitoring "critical reliability parameters."

For proposed measure PM1, RTBPTF believes that Requirement R1 works in conjunction with RTBPTF's recommendations for Standard IRO-002 and recommendations for modifications to the update frequency as mandated by Standard TOP-005 for "generation and transmission resources available for use." RTBPTF interprets this requirement as the active monitoring of bulk electric system elements (i.e., status of all generation and transmission resources available for use) within the entity's area of responsibility. In addition to monitoring of the status of all generation and transmission resources available for use, the critical reliability parameters specified in Requirement R1 could be derived using a capacity assessment (or equivalent) application. The capacity assessment (or equivalent) application gives an overview of available generation capacity (MW or Mvar) in real time. Telemetry data indirectly support the capacity assessment application output/solution. Section 2.12 of this report, Capacity Assessment, discusses the recommendations for the capacity assessment application.

For proposed measure PM2, RTBPTF believes that Requirement R2 works in conjunction with RTBPTF's recommendations above for modifications to update frequency as mandated by Standard TOP-005. RTBPTF interprets this requirement as the active monitoring of bulk electric system elements (i.e., applicable transmission-line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources) within the entity's area of responsibility by using the entity's telemetry data systems.

For proposed measure PM3, RTBPTF supports the notion of operators having access to documentation of appropriate technical information concerning protective relays.

For proposed measure PM4, RTBPTF believes that operators need historical/real-time/forecast weather information. These types of information are readily available from the Internet. The measure for this requirement mandates that weather information that may affect the real-time and forecasted load needs to be accessible to operators and used by the entity's near-term load forecast systems.

For proposed measure PM5, RTBPTF reiterates the need for demonstrated usage of monitoring equipment (such as telemetry data systems and/or alarm tools) to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

For proposed measure PM6, RTBPTF interprets "timely monitoring" as following the update frequency mandated by Standard TOP-005, "Electric System Reliability Data" appendix. An entity may choose to exceed the minimum requirement mandated by the appendix to ensure timely dissemination of critical information for operating personnel.

For proposed measure PM7, RTBPTF believes that reliability entities should demonstrate compliance by having displays (or visualization tools) that show real-time frequency from all telemetry sources.

7. NERC Reliability Standard VAR-001, Voltage and Reactive Control

The purpose of Standard VAR-001 is "to ensure voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in ***real time*** [emphasis added] to protect equipment and the reliable operation of the Interconnection." Requirement R1 mandates that "each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators." Standard VAR-001 (Requirement R1) does not specify any measures for compliance.

RTBPTF Recommendation

RTBPTF recommends that a measure be established for Standard VAR-001 (Requirement R1) that requires the documentation of formal policies and procedures to ensure voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the interconnection. The following measure is recommended for Standard VAR-001 (Requirement R1):

PM1. Each transmission operator shall document formal policies and procedures to ensure voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the interconnection. These formal policies and procedures shall include the list of bulk electric system elements that need to be monitored via telemetry, such as voltage telemetry levels (from generators, transmission substations, etc.), reactive flows (from generators, transmission substations, transmission lines, etc.), and reactive power resources (static and dynamic). This document shall be made readily available to operators and updated as necessary.

Rationale

The Real-Time Tools Survey results described in the Summary of Findings section above show that ***not*** all voltage levels, reactive flows, and reactive resources are available as telemetry data. Standard VAR-001 mandates "real-time" monitoring of these data. As stated previously, RTBPTF believes that "monitoring" does not imply viewing large amounts of raw telemetered data but rather viewing data in a manner and format that allows operators to rapidly judge the state of the bulk electric system and take corrective action if necessary. Transmission operators could use a state estimator (with defined measurement-observability requirements) to monitor voltage levels, reactive flows, and reactive resources in real time. To protect equipment and maintain reliable operation of the interconnection, the pre- and post-contingency analysis solution could also be used to monitor voltage levels, reactive flows, and reactive resources in real time and assess impacts of contingencies on the reliability of the interconnection.

8. NERC Reliability Standard COM-001, Telecommunications

Each RC, TOP, and BA needs adequate and reliable telecommunications facilities internally and to others for the exchange of the interconnection and operating information necessary to maintain reliability. Requirement R2 states "each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test, and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications."

RTBPTF Recommendation

Knowledge of the status of vital telecommunications facilities and equipment via telemetry internally and to/from related entities is essential for situational awareness. The telemetry data required to fulfill this requirement are closely tied to the issues addressed in Section 5.3, Facilities Monitoring, of this report. Section 1.2, ICCP-Specific Data, of this report addresses the methodology and management issues related to ICCP-specific data exchange. RTBPTF recommends rewording Requirement R2 as follows:

> R2. Each reliability coordinator, transmission operator, and balancing authority shall manage, alarm, test, and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications. At a minimum, reliability coordinators, transmission operators, and balancing authorities shall provide telemetry data by vital telecommunications equipment (1) internally, (2) between the reliability coordinator and its transmission operators and balancing authorities, and (3) with other reliability coordinators, transmission operators, and balancing authorities.

Rationale

RTBPTF believes that the new language recommended for Requirement R2 specifies the types of telemetry data systems (telecommunications facilities) that are required (i.e., to support internal communications within the entity's area of responsibility, communications between the reliability coordinator and its transmission operators and balancing authorities, and communications with other reliability coordinators, transmission operators, and balancing authorities.)

Recommendations for New Operating Guidelines

RTBPTF does not recommend development of new operating guidelines for telemetry data at this time. The recommendations listed within this section indicate the need to clarify measurement methods specified in existing standards and compliance procedures. These clarifications are necessary before establishing new operating guidelines for telemetry data.

Areas Requiring More Analysis

RTBPTF is not recommending additional areas for analysis related to Telemetry Data.

Examples of Excellence

RTBPTF cites the Northeast Power Coordinating Council's "Criteria for Classification of Bulk Power System Elements (A-10)[18]" document as an example of excellence in establishing and facilitating a process/methodology for classifying bulk power system elements (See EOE-1 in Appendix E).

[18] http://www.npcc.org/documents/regStandards/Criteria.aspx

Section 1.2
ICCP-Specific Data

Definition

The Inter-Control Center Communications Protocol (ICCP) is a standard data-exchange format that is widely used in the electric utility industry to communicate information among operating entities.

Background

ICCP data are exchanged among reliability coordinators in the NERC ISN. In addition, several intra-regional and intra-company networks use ICCP to provide data to reliability coordinators from operating entities within each reliability coordinator's footprint.

Questions[19] in the ICCP-specific data section of the NERC Real-Time Tools Survey address ICCP data-exchange management and methodology. The survey questions examine issues and practices that affect the adequacy, quality, and timeliness of data ultimately provided to real-time tools for analyzing the reliability of the bulk electric system.

Summary of Findings

The majority of respondents to the NERC Real-Time Tools survey rate ICCP-specific data as essential to conducting reliability assessments and maintaining situational awareness. In addition, ICCP data are also rated as essential to generating accurate state estimator solutions. However, analysis of survey responses identifies the following problems and issues related to ICCP data:

- a lack of availability of the systems that supply ICCP data, including, notably, data-link failures
- a lack of data coordination and quality
- an absence of documented processes and procedures for managing ICCP systems
- a lack of timely responses to requests for ICCP data updates
- an extended or unknown period of data latency
- restricted access to some data

Based on analysis of the Real-Time Tools Survey results, RTBPTF recommends the following new reliability standards:

- All TOPs must have ICCP or equivalent systems subject to the same standard as RCs.
- Data-exchange coordination requirements must be imposed.

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[19] RTBPTF relied extensively on the EPRI *Inter-Control Center Communications Protocol (ICCP) User's Guide* as a reference (EPRI TR-107176) to prepare survey questions.

- A requirement and measure of data-exchange-system reliability must be established.
- A minimum trouble-response time must be specified.
- Documented procedures must be established for activities such as data maintenance and update, data naming, and alarm response.
- ICCP systems must have redundant components to avoid data exchange interruptions.

The analysis of survey responses also reveals that systems equivalent to the NERC ISN are in use. Therefore, the task force recommendations should apply to both ISN and equivalent systems. The recommendations that follow the survey findings subsection below are written to apply to any type of data exchange system equivalent to the NERC ISN.

The task force does not recommend the creation of operating guidelines for ICCP data at this time.

The areas identified for more analysis include data latency, time skew, and time stamping and mapping of data to real-time tools.

The NERC Operating Reliability Subcommittee (ORS) specifically requested that RTBPTF investigate current practices of entities that exchange data via ICCP because of concerns about ICCP data quality and availability as well as ICCP's prevalence within the industry for exchanging operating reliability data.
The NERC Real-Time Tools Survey explores the various systems that survey respondents use to receive ICCP data. Approximately 50 percent (27 out of 55) of respondents report that they receive data through a direct connection to the ISN. In addition, more than 78 percent (43 out of 55) report that they also receive ICCP data via direct connections to other entities' systems, and approximately 45 percent (25 out of 55) receive ICCP data via data links internal to their companies. These results clearly show that equivalent systems are widely used in addition to the ISN. This finding has important bearing on the applicability of reliability standards governing data exchange. This issue is discussed further below in the subsection "Recommendations for New Reliability Standards."

The overwhelming majority, 75 percent (41 out of 55), of all respondents to the ICCP data section of the survey rate their ICCP data as "essential" for the value it adds to their situational awareness. All reliability coordinators rate ICCP data as "essential." The survey respondents make the following comments regarding the criticality of ICCP data:

> "Essential for state estimation and visual monitoring of non-owned areas."
>
> "ICCP data [are] essential for real-time security assessment."

> “In carrying out the RC role, ICCP information is required from BAs within [the] RC footprint.”
>
> “Our operators have tools that require ICCP data to work properly.”
>
> “The ICCP data [are] applied to the state estimator model to make the model observable in real-time.”
>
> “It [ICCP data] fills in holes in our data, provides backup on ties with neighbors, and provides a ‘wider’ view of the system.”

Although ICCP data are considered essential by the majority of survey respondents, the survey results reveal that these data are not consistently available in many cases. Approximately 58 percent (29 out of 50) of respondents have self-imposed availability requirements of 99 percent or higher for their ICCP systems. However, only 7 of the 13 RCs that have availability requirements report that they actually meet their own requirements.

ICCP data are used by most respondents (especially RCs) to perform state estimation. However, the survey responses indicate that ICCP system data-link failures rank highest on the list of ICCP-related problems affecting the ability of state estimators to generate a solution (see Table 1.2-1). One respondent made the following comment regarding the frustration resulting from losing a data link:

“Our biggest issue is with failure of entire ICCP data links from the data providing entity. We have issues with losing ICCP data from an entire utility on a periodic basis.”

The problem of ICCP data link failures is largely a result of lack of redundancy. Nearly one-third of all respondents (17 out of 53) report that they do not have redundant data links. Note that respondents report a higher level of redundancy for other aspects of their ICCP systems than for their data links. For example, nearly 90 percent (47 out of 53) of respondents have redundant ICCP servers, and nearly 78 percent (41 out of 53) have redundant network connections.

Other commonly reported ICCP-specific data problems that affect state estimator solutions include lack of maintenance coordination with other entities, poor data quality, and failover problems (see Table 1.2-1). One reason for frequent data coordination and quality problems is that fewer than half of the respondents (23 out of 49) have formal agreements with other entities that specify how data-set changes are to be communicated, coordinated, and tested. RTBPTF concludes that data-coordination requirements are necessary to alleviate many of the problems that affect state estimator solutions. These requirements will help ensure operators’ ability to assess transmission system reliability and maintain situational awareness.

ICCP Problems Impacting State Estimator Solutions	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Other	Total
Data Link failure on your end	X	X	X	X				X	X	X				X	X			19	**28**
Data Link failure on the other end	X	X	X	X	X	X	X	X	X	X		X	X	X	X	X		20	**35**
Invalid, failed, or corrupted data received	X	X	X	X	X	X	X	X	X		X	X						13	**24**
Failover Problems	X	X	X			X	X	X					X					7	**14**
Uncoordinated maintenance activities (in house)	X	X		X	X		X											5	**10**
Uncoordinated maintenance activities (external)	X	X	X			X	X			X	X							10	**17**
Data time skew (i.e., mixing stale ICCP data with fresh SCADA data)	X	X	X	X		X												2	**7**
Software bugs	X	X						X						X				5	**9**
Interoperability issues (i.e., version incompatibility, user object incompatibility)		X		X	X													5	**8**
Extended bad quality indication	X				X				X									3	**6**

Table 1.2-1 — ICCP Problems Impacting State Estimator Solutions[20]

Most respondents report that they have very few documented processes or procedures for managing their ICCP systems (see Table 1.2-2). Although approximately 65 percent (32 out of 49) of all respondents have documented data-naming conventions, less than half have data-maintenance procedures (23 out of 49) or documented EMS data-mapping standards (19 out of 49), and only about 25 percent have documented test procedures (14 out of 49) or documented procedures for monitoring and measuring data-link performance (12 out of 49) and data availability (13 out of 49). In addition, only 60 percent (16 out of 27) of all respondents that exchange ICCP data via the NERC ISN indicate that they have the NERC *Data Exchange Working Group (DEWG) ISN Node Responsibilities and Procedures Document* even though this document is posted on the NERC web site. Even RCs, who are generally considered to maintain more documentation than TOPs and BAs (see Table 1.2-2), report very little.

The survey was not designed to allow respondents to identify by name other entities that do not perform well in providing consistently accurate, timely, and up-to-date data sets via ICCP data exchange. Therefore, it is not possible to use the survey responses to determine a correlation between the type and quality of an entity's documentation of internal processes and procedures and that entity's performance of ICCP data exchange as judged by those with whom the entity

[20] RC responses are indicated with "X." Aliases are used as column headers to mask the RCs' names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, "RC 1" in any given table may not be the same as "RC 1" or the equivalent identifier in another table in this report.

exchanges data. Several entities (particularly RCs) that report that they exchange large quantities of data via ICCP and that are known by RTBPTF members to perform those functions reasonably well report having several different types of documented processes and procedures. Therefore, the task force concludes that the lack of a consistent set of documentation is a significant impediment to an entity's ability to maintain its ICCP data exchange.

Documented ICCP Processes and Procedures	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**RC17**	**Others**	**Total**
Data-naming conventions	X	X	X	X	X	X	X	X	X	X	X	X	X					17	**30**
EMS data-mapping standards	X	X	X	X	X	X	X		X	X	X			X				8	**19**
Data maintenance procedures	X	X	X	X	X	X	X	X		X	X	X						11	**22**
Troubleshooting guidelines or procedures	X	X	X	X	X		X	X	X	X								14	**23**
Test procedures	X	X		X	X	X	X				X		X					3	**11**
Data-set creation procedures	X	X	X	X			X	X	X			X						11	**19**
Data availability monitoring and measurement	X	X	X	X		X		X	X	X								4	**12**
NERC DEWG ISN node responsibilities and procedures document	X	X		X	X	X	X				X	X						6	**14**
Data-link performance monitoring and measurement	X	X	X		X	X							X					4	**10**
Fault management procedures (i.e., error statistics analysis, lost connection response)	X	X	X		X			X										2	**7**
Associated management procedures	X	X	X						X									5	**9**

Table 1.2-2 — Documented ICCP Processes and Procedures[21]

Another data-coordination and management problem identified in the survey is timeliness of responses to requests for data set updates. Respondents report a wide range of turn-around times for these requests. Very few respondents (4 out of 50) report receiving same-day service for data-set updates, and only 30 percent (15 out of 50) report that they usually receive a response within a week. Still others have to wait up to two weeks (6 out of 50) or even as long as a month (5 out of 50) for a data-set update. In addition, several respondents (18 out of 50) report that response times for data set update requests depend upon the particular data provider.

The survey asked several questions related to data latency and its effects, but the responses are inconclusive. When asked how long it takes from the time a data point changes in the field until that change is represented in their local EMS

[21] Reliability coordinator responses are indicated with "X." Aliases are used as column headers to mask the RCs' names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is "RC 1" in any given table may not be the same as "RC 1" or the equivalent identifier in another table in this report.

database (i.e. data latency), respondents report a broad range of data latency times ranging from a few seconds to a few minutes, and several do not know their data latency times (see Table 1.2-3). A few respondents identify time skew (defined here as the time difference between stale ICCP data and fresh SCADA data) as contributing to solution problems for their state estimators. Finally, the vast majority of respondents report that there are no time stamps on the ICCP data that they send (35 out of 51) or receive (27 out of 49). The task force concludes that more analysis and review of data latency and its impact on reliability assessment and situational awareness are needed before definitive minimum requirements can be established.

In Section 1.1, Telemetry Data, of this report, RTBPTF recommends decreasing the required update frequency for operational reliability data from 10 minutes to 10 seconds. If this recommendation is implemented, some data latency impacts should be reduced. However, unless “updates” are always made with fresh data (rather than simply forwarding old data to recipients every 10 seconds until fresh data are available from the source), there will be few improvements in data latency.

Analog Point Data Latency	***Responses***		**Status Point Data Latency**	***Responses***
< 4 seconds	4		< 4 seconds	5
< 10 seconds	4		< 10 seconds	14
< 30 seconds	16		< 30 seconds	8
< 1 minute	12		< 1 minute	6
< 5 minutes	4		< 5 minutes	5
10 minutes or less	0		10 minutes or less	2
Don’t know	6		Don’t know	7
Other	4		Other	3

Table 1.2-3 — ICCP Data Latency

NERC Reliability Standard TOP-005-0, Operational Reliability Information, requires RCs, TOPs, and BAs to provide data to one another for the purpose of performing operational reliability assessments and coordinating reliable operations unless otherwise agreed. Requests for these data are often rejected for a variety of reasons, as indicated in Tables 1.2-4 and 1.2-5. The survey results raise the question of whether this requirement is being consistently met. The task force concludes that the industry requires specification of what can be considered a legitimate restriction to data access.

Criteria Used by Respondents to Restrict Access to Data	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Permission from data owner	X	X	X	X	X	X	X	X			X			X		X		26	**37**
Justification of need by requestor	X	X	X	X	X	X	X		X	X		X						26	**36**
Market-sensitive data	X	X	X	X	X	X		X	X	X	X	X	X		X			19	**32**
Technical limitation (i.e., server size, communication bandwidth)	X	X																9	**11**
Resource limitation (i.e., maintenance/support overhead)																		6	**6**
Software license limitation																		5	**5**
None																		1	**1**

Table 1.2-4 — Criteria Used by Respondents to Restrict Access to Data

Suppliers' Constraints Restricting Respondents' Access to Data	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Permission from data owner	X	X	X	X	X	X		X		X		X						27	**36**
Justification of need not accepted by supplier	X	X	X	X	X		X		X									15	**22**
Market-sensitive data	X	X	X			X	X	X	X		X							20	**28**
Technical limitation (i.e., server size, communication bandwidth)	X																	7	**8**
Resource limitation (i.e., maintenance/support overhead)																		7	**7**
Software license limitation																		2	**2**
None													X	X	X	X		3	**7**

Table 1.2-5 — Suppliers' Restrictions on Respondents' Access to Data

Survey respondents identify operator awareness of ICCP system health as an important issue. Approximately 80 percent (41 out of 51) state that their system operators monitor the status of their ICCP data links. Approximately 70 percent (35 out of 51) of respondents provide audible alarms to make operators aware of ICCP system problems, and 50 percent (26 out of 51) have ICCP system "health" visualization displays for their operators. Operators must be quickly made aware when state estimator solutions may be unreliable because of ICCP data problems.

The August 14, 2003 *Outage Task Force Final Blackout Report* finds that the reliability data that MISO was receiving via the ECAR data network and other data links were not linked (mapped) so that MISO's state estimator could be automatically informed of status change of a key transmission line.[22] The Real-

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[22] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. page 48.

Time Tools Survey explored this issue by asking respondents to quantify the ICCP status point data and ICCP analog data they receive that are mapped into respondents' real-time network application databases and used by these applications. The results are summarized in Tables 1.2-6 and 1.2-7. Most RCs, as expected, map a large percentage of the ICCP data they receive, as do many other respondents, but a few RCs and other respondents could improve in this area.

Mapping ICCP data to a real-time network model database often requires that the model be modified to provide sufficient detail to allow linking of specific data. For example, an external station represented as a bus-branch model will have to be expanded to include circuit breakers at the correct locations to permit mapping of specific breaker status points to the correct devices. This effort is resource intensive; resource constraints may have prevented some respondents from performing all of the mapping that they ultimately intend to accomplish. This could be one reason that some respondents report low mapping percentages (or do not reply to this question at all). The task force concludes that the specific data that should be mapped to real-time tools are dependent upon the NERC definitions of bulk electric system and wide-area view. As previously stated, the task force believes that these definitions are unclear. Therefore, the task force concludes that the issue of data mapping requires more analysis.

ICCP Status Point Data Mapped to Real-Time Tools	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC 17	Others	Total
All	X	X																15	**17**
> 90 percent			X	X	X	X	X	X	X	X	X	X						3	**13**
> 75 percent													X	X	X	X		2	**6**
> 50 percent																		1	**1**
> or = 25 percent																		1	**1**
< 25 percent																		3	**3**
None																		8	**8**
Unanswered																	X	5	**6**

Table 1.2-6 — ICCP Status Point Mapping

ICCP Analog Data Mapped to Real-Time Tools	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC 17	Others	Total
All	X	X																12	**14**
> 90 percent			X	X	X	X	X	X	X	X								5	**13**
> 75 percent											X	X	X	X	X			1	**6**
> 50 percent																X		1	**2**
> or = 25 percent																		2	**2**
< 25 percent																		3	**3**
none																		9	**9**
unanswered																	X	5	**6**

Table 1.2-7 — ICCP Analog Mapping

Survey respondents were asked to quantify how long it takes to resolve problems internal to their systems and how long it takes responsible external entities to respond to and resolve problems in those entities' systems. Table 1.2-8 summarizes the responses. A large majority, 76 percent (38 out of 50) of respondents, can resolve internal problems within one hour. Only 44 percent (22 out of 50) can get external problems resolved within one hour; however, 74 percent (37 out of 50) can get resolution within two hours. The task force concludes that these time frames are achievable and necessary thresholds for a trouble-response standard because of the importance of these data for maintaining reliability.

Trouble Response Time Range	*Internal Problems*		*External Problems*
< 1 hour	38		22
1-2 hours	6		15
2-4 hours	3		1
4-8 hours	2		7
> 1 day	0		1
Other(s)	1		4

Table 1.2-8 — ICCP Trouble-Response Times

Survey respondents report various methods for creating ICCP object IDs. Approximately 58 percent (29 out of 51) of respondents create globally unique data names used by all parties. Twenty-seven percent report using the object names provided by the source. Only about 12 percent (6 out of 51) of respondents generate sequential numbers for ICCP object IDs, and an overwhelming majority, 76 percent (38 out of 51), have a structured naming convention such as a composite key (i.e., Station ID + Device ID + Point ID, etc.). Recent discussions in the ISN community have identified data recipients' difficulty in keeping abreast of data-point name changes instituted by data providers. It is widely recognized that the names of data points utilizing a composite key naming convention are likely to change when some component of the name changes, such as when a station is renamed or a device is replaced with a different type of device (replacing a switch with a breaker, for example). By contrast, data points named with sequentially generated numbers are unlikely to need changing. Nevertheless, the Real-Time Tools Survey indicates that composite key names are much more common than sequential numbers, probably because data providers who create the names find it easier for purposes of data point checkout and testing to list data point details within the name. Despite these issues, the task force concludes that a standard naming convention would be difficult to implement and therefore does not recommend one. Instead, RTBPTF recommends that this issue be addressed in comprehensive standards governing all aspects of data-exchange coordination.

Recommendations for New Reliability Standards

Based on analysis of the Real-Time Tools Survey results, RTBPTF recommends the following:

- All transmission operators must be required to have ICCP or equivalent systems subject to the same standard as reliability coordinators.
- Data-exchange coordination requirements must be imposed.
- A requirement and measure of data-exchange-system reliability must be established.
- A minimum trouble-response time must be specified.
- Documented procedures must be established for activities such as data maintenance and update, data naming, and alarm response.

- ICCP systems must have redundant components to avoid data-exchange interruptions.

Each of these recommendations is described in detail below.

NERC Standard TOP-005-0, Operational Reliability Information, currently specifies several general requirements (R1 – R5) and one measure (M1) to "ensure reliability entities have the operating data needed to monitor system conditions within their areas." The requirements do not specify use of the ICCP protocol; however, requirement R3 refers as follows to the NERC ISN, which utilizes ICCP for data exchange:

> Upon request, each reliability coordinator shall, via the ISN or equivalent system, exchange with other Reliability Coordinators operating data that are necessary to allow the Reliability Coordinators to perform operational reliability assessments and coordinate reliable operations.

The results of the Real-Time Tools Survey indicate that several other regional networks over which operational reliability data are exchanged also use the ICCP protocol. The task force concludes that these regional networks should be considered "equivalent systems." Some other data-exchange arrangements do not use the ICCP protocol but arguably could be considered "equivalent systems." Requirement R3 of TOP-005-0 applies only to RCs; however, survey respondents clearly indicate, as noted in the Survey Findings section above, that ICCP data are essential for reliability assessment and situational awareness, including the ability to produce a state estimator solution. The task force concludes that ICCP and "equivalent systems" are critical reliability tools for both RCs and TOPs. Therefore, the task force recommends as follows.

RTBPTF Recommendation

> All Transmission Operators shall have ICCP or equivalent systems for data exchange and shall be subject to the same standards for this tool as reliability coordinators. Other responsible entities who are using ICCP or equivalent systems to support or complement their reliability coordinator's ability to operate the bulk electric system reliably in accordance with formal agreements, contracts, or established practices or procedures, shall be subject to the same standards for ICCP or equivalent systems as their reliability coordinator's.

The task force believes that this statement of applicability is also consistent with Requirement R3 of Reliability Standard IRO-002, Reliability Coordination – Facilities, which states:

> Each reliability coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data

exchange to other reliability coordinators or Transmission Operators and Balancing Authorities via a secure network.

Each of the following recommendations is written to apply to any type of data exchange system used to support compliance with NERC Reliability Standard TOP-005-0.

Recommendation – S4

Develop data-exchange standards

Data Exchange Coordination Standards

Survey respondents identify a number of issues related to ICCP data exchange, as noted in the Survey Findings section above.

RTBPTF Recommendation

RTBPTF recommends that new requirements be added to standard TOP-005 that apply to all users and providers of data exchanged by ICCP or equivalent systems. These requirements will standardize the procedures, processes, and rules governing:

- Interoperability of ICCP and equivalent systems
- Data access restrictions
- Data-naming conventions
- Change management and coordination
- Joint testing and data checkout
- Quality codes
- Dispute resolution

This recommendation is also related to the issue of change management procedures for real-time models, as discussed in Sections 4.1, Model Characteristics, and 4.2 Modeling Practices and Tools, of this report. The task force recognizes the work already completed by NERC DEWG in these areas, which is documented in the *ISN Node Responsibilities and Procedures Document*.[23] The task force considers this work a good starting point for definitive and comprehensive requirements. The task force recommends that the *ISN Node Responsibilities and Procedures Document*, which currently does not have the force and effect of a standard, evolve into a standard developed in accordance with the recommendations of this report.

[23] http://www.nerc.com/~filez/isn.html

Availability requirements

The survey respondents identify problems associated with failure/lack of availability of systems providing ICCP data, particularly failures of data links, which directly impact state estimator solutions. The task force recommends that NERC Standard TOP-005-0 be revised to incorporate a requirement and a metric for data-exchange system availability. The fact that many entities have self-imposed availability requirements is evidence of the desirability of such a metric. The revised standard should specify how availability is to be calculated and measured.

RTBPTF Recommendation

The task force recommends that each data recipient track the availability of data from each provider of ICCP or equivalent system data. Each time a data set is received, the recipient would calculate the ratio of the number of data points received with “good” quality codes to the total number of data points expected. This ratio should exceed 99 percent for 99 percent of the sampled periods (i.e., 10 seconds each) over a calendar month. In addition, this ratio should not be less than 99 percent for 30 consecutive minutes.

Requiring data recipients to calculate data availability will reveal problems affecting data quality or availability anywhere in the data stream. RTBPTF also recommends that data providers be required to monitor availability of internal data systems used to provide data to others. Recommended standards for data system availability monitoring are included in the general recommendations in Section 5.4, Critical Applications Monitoring, of this report.

The following diagram (Figure 1.2-1) is an example of the distribution of responsibilities for data availability calculation and monitoring.

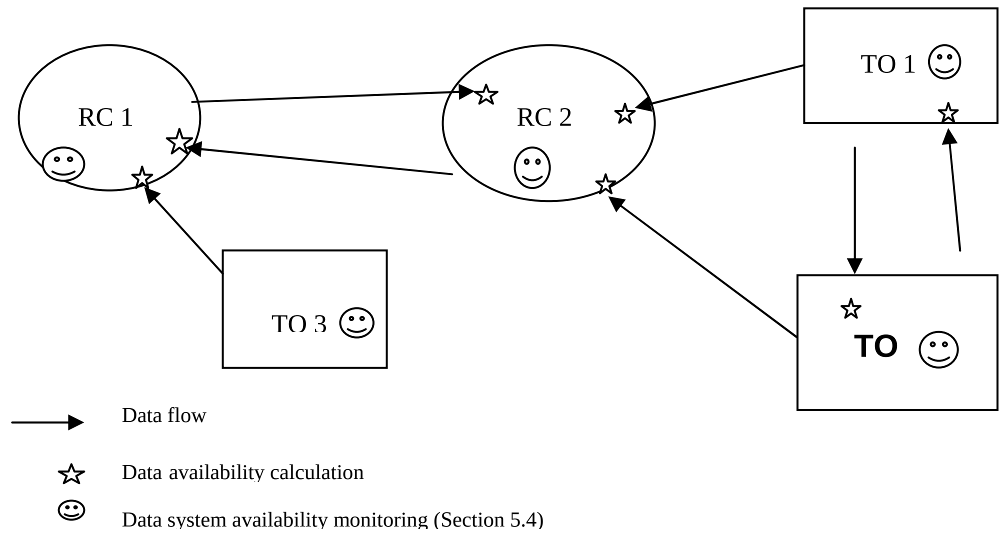

Figure 1.2-1 — Example of Data Distribution Responsibilities

Recommendation – S5

Develop data-availability standards and a process for trouble resolution and escalation

Trouble-response times

The internal and external trouble-response times reported by survey participants, as noted in the Survey Findings section above, are achievable thresholds for a trouble-response standard.

RTBPTF Recommendation

The task force recommends the establishment of minimum response times for the restoration of data exchange among control centers following the loss of a data link or other problems within the source system. These minimum requirements could be incorporated within the data-exchange coordination standards recommended above. Alternatively, minimum response times could be specifically defined as a new requirement and a new measure under NERC Standard TOP-005-0. In addition, the task force recommends the development of a trouble-resolution process that would be mandatory for all entities responsible for the management and maintenance of ICCP or equivalent systems that could be the cause of a loss of data-exchange capability with another system. These entities would be required to identify a mutually agreeable restoration target time with affected data recipients. The standard process would also include service restoration procedures and prioritization criteria.

Maintenance and management documentation

Most survey respondents possess very few documented procedures for managing their ICCP systems, as reported in the Survey Findings section above.
RTBPTF Recommendation
The task force recommends that all entities responsible for managing and maintaining ICCP or equivalent systems be required to have documented procedures for the support activities necessary to ensure compliance with the current and recommended requirements of NERC Standard TOP-005-0. At a minimum the following procedures and activities should be documented:

- Data maintenance and updates
- Testing
- System availability monitoring and measurement
- Troubleshooting
- EMS (real-time network applications) data-mapping standards
- Data-naming conventions
- Fault management (maintenance and display of error statistics)
- Alarm response

The task force recommends that NERC Standard TOP-005-0 be revised to incorporate a requirement and a measure for the above procedures. These procedures should be subject to self-certification and should be reviewed for completeness during the NERC compliance audits.

ICCP or equivalent system component redundancy

The Real-Time Tools Survey revealed a high degree of redundancy in respondents' ICCP systems. Note that redundant components support a high degree of system availability by ensuring that a single failure point will not make the system unavailable. The survey also revealed that some ICCP or equivalent systems did not have redundant data links. Many respondents identified the loss of a data link as a serious failure impacting the ability of their state estimators to produce accurate solutions.

RTBPTF Recommendation

Requirement R1.4 of NERC Reliability Standard COM-001-0, Telecommunications, requires that "where applicable" telecommunications facilities "shall be redundant and diversely routed." The task force recommends that this requirement be expanded to specifically state that it applies to ICCP and equivalent systems. The standard should also require that all system upgrades, expansions, and replacements include the elimination of single points of failure.

Recommendations for Operating Guidelines

RTBPTF does not recommend the development of new operating guidelines pertaining to ICCP or equivalent systems.

Areas Requiring More Analysis

RTBPTF concludes that time skew, time stamp, and data latency require additional analysis by NERC.

Recommendation – A1

Investigate the impact of time skew on state-estimator solution quality.

Time skew and time stamping

The impact of data time skew on state estimator solution quality has been the subject of various technical papers during the past several years. The survey responses related to time skew and data latency were too general to allow the task force to identify a specific requirement for maximum data latency or minimum time skew based upon actual (as opposed to theoretical) experience. More detailed investigation, testing, and analysis are necessary before any standards can be developed, including requirements for time stamping of ICCP data or equivalent system data.

The task force recommends that NERC DEWG be tasked with studying these issues with the goal of "informing" the standards-setting process and identifying cost-effective standards or operating guidelines that would minimize the impacts of stale data on real-time reliability analysis and situational awareness.

Additionally, the task force recommends that DEWG validate or confirm the task force's recommendation in Section 1.1, Telemetry Data, of this report to revise the timing requirements in Attachment 1 of NERC Standard TOP-005. DEWG should also consider the data update requirements (periodic or by exception) necessary to support the requirements in NERC Standard IRO-002. Special consideration should be given to the communication of event-driven system changes such as a transmission-line trip that RCs need to analyze in real time.

Recommendation – A2

Identify necessary fidelity and scope of real-time models and the extent of the requisite data-exchange sets.

Mapping of data to real-time tools

The specific data that an RC, TOP, or other entity responsible for reliability should request from neighboring or nearby entities and map into its real-time tools databases or models is a function of many variables. Among these variables are the size and location of the entity, the "footprint" for which the entity is responsible, and the view of the external area necessary to monitor and coordinate system operations reliably. These same variables affect the extent and fidelity of the real-time models that must be built and maintained in order to perform real-time functions such as state estimation and contingency (security) analysis. The necessary fidelity and scope of real-time models and the extent of the requisite data-exchange sets needed to map to the models are ultimately dependent upon the definitions of bulk electric system and wide-area view. Section 1.1, Telemetry Data, of this report discusses the need to clarify the definition of bulk electric system, and Section 2.1, Alarm Tools, discusses the definition of wide-area view. Furthermore, Sections 4.1, Model Characteristics, and 4.2, Modeling Practices and Tools, recommend additional analyses of modeling criteria, especially as those criteria apply to areas external to an entity's footprint. This analysis should also explore the criteria for determining what external measurements must be mapped into the portions of real-time models representing areas external to an entity's area of responsibility.

Examples of Excellence

RTBPTF cites an automated trouble-tracking system that includes processes and procedures for reporting, notification, tracking, resolution, and escalation of ICCP data problems used by Independent System Operator (ISO) New England and its transmission owners as an example of excellence (See EOE-2 in Appendix E).

RTBPTF cites an automated monitoring system that periodically compares data-set time stamps to detect and alarm any data sets that have stopped updating for any reason used by ISO New England and its transmission owners as an example of excellence (See EOE-3 in Appendix E).

Section 1.3
Miscellaneous Data

Definition

Miscellaneous data are used by real-time applications/tools that may not be supported by basic SCADA and/or ICCP systems. Miscellaneous data include information on weather such as that available from commercial data services as well as information from sources such as substation relays, recorders, and monitoring units.

Background

Chapter 7 of the *Outage Task Force Final Blackout Report* includes an examination of causal factors common to all major outages during the past 40 years.[24] One cause common to several events (although not the August 14 blackout) was severe weather conditions. Examples include lightning storms, extreme heat, and high winds. Even though the blackout that led to the creation of RTBPTF was not specifically weather related, the lack of situational awareness is a recurring theme in the blackout report. The task force believes that the issue of situational awareness from an operator's perspective would be inadequately addressed without an investigation of weather data and their application in control centers. The investigation of the other types of miscellaneous data documented in this section of the report is intended to uncover situational awareness issues that might be addressed by less common or less familiar data.

The Real-Time Tools Survey miscellaneous data section encompassed weather, fault locator, and high-speed sampled data.

Summary of Findings

Survey results reveal that almost all respondents rely to some extent on weather data and perceive these data as valuable for situational awareness; in contrast, respondents do not rely on fault locator data and high-speed sampled data (including phasor data) to monitor system conditions in real time and maintain reliability. Based on these findings, RTBPTF recommends modifying existing standards to require that weather data be provided to operators but does not recommend new standards for fault locator or high-speed sampled data. The task force notes, however, that phasor measurement data are part of other current industry initiatives, and that NERC's *Reliability Standards Development Plan: 2007-2009* includes the possibility of a new standard for PMUs.

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[24] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. pp. 107-110.

Meteorological Data

Almost all survey respondents rely on meteorological data to some extent. Nearly 90 percent (47 out of 53) of the respondents to this section of the survey reported using some type of meteorological data to support situational awareness. Approximately 38 percent (18 out of 47) of those who use this type of data consider it “essential” or required for situational awareness, and almost half (23 out of 47) consider it ”desirable” and an enhancement of their operational capabilities.

Survey comments indicate that many respondents use weather data to improve load forecasts and monitor potential impacts of severe weather on system reliability. Others use data such as temperature and wind speed to calculate thermal limits. Less common uses of meteorological data include forecasting expected wind-generation levels and determining when to expedite transmission-line maintenance outages. Table 1.3-1 summarizes the types of meteorological data currently being monitored and used in real-time tools.[25]

Monitored (M) / Used (U)	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others
Temperature	M/U	M	M/U	M/U	M/U	M	U	M	U	M/U	M	M						26/8
Wind Speed/Direction	M/U	M	M	M	M/U	M	M		U	M/U		M						21/4
Relative Humidity	M	M	M/U	M		M			U		M							16/3
Dew Point	M	M	M/U	M/U	M/U	M			U									6/2
Ice Thickness	M	M					U											4/0
Cloud Cover	M		M		M/U													11/2
Lightning Information	M					U	U	M										16/2
Precipitation	M	M		M				M										18/0

Table 1.3-1 — Meteorological Data Monitored (M) and Used (U) in Real-Time Tools

Survey respondents place high value on meteorological data for supporting real-time operational capabilities and situational awareness. The following comments by respondents highlight the perceived value of weather data:

> “Knowing weather conditions throughout the state is essential to system operations.”

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[25] Aliases are used as column headers to mask RC-s’ names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, “RC 1” in any given table is not the same as “RC 1” or the equivalent identifier in another table in this report.

> “You cannot have an accurate load forecast without good weather data.”

> “Weather information is essential to understanding and preparing for activity on the system.”

> “Wind speed and lightning information is used in determining when to restore lines early, from maintenance outages.”

> “We use meteorological data to calculate thermal limits and to monitor thunderstorms and ice storms.”

The survey asked how meteorological data are presented to operators. Approximately 61 percent (28 out of 46) of respondents provide these data on dynamically updated, dedicated EMS displays, and about 24 percent (11 out of 46) have dynamically updated, multi-purpose dashboard displays to support situational awareness. Other less commonly used methods of data presentation include: periodic reports, cable television, weather services via the Internet, and corporate meteorological department intranet web pages.

Because of the perceived value and prevalent usage of meteorological data for situational awareness, RTBPTF recommends adding a new requirement to an existing standard to address the necessity of providing weather data to operators.

Fault Locator Data

Survey results generally reveal that, when a fault causes a facility outage, fault locator data facilitate restoration. Almost 60 percent (30 out of 51) of respondents use fault locator data, but only about 20 percent (4 out of 21) of those who do not use it plan to add it in the future. Only 6 respondents who use these data rate them “essential“ for situational awareness. All but one of the other users consider these data ”desirable” for situational awareness. The following comments by survey respondents indicate the perceived value of fault locator data:

> “Fault location data is required for effective restoration after an outage. Written procedures require fault location data before circuit tests are performed.”

> “Reduces repair time and facilitates quicker isolation and partial restoration.”

> “We use the distance data of the distance relay flagged in every line fault.”

The survey also asked how fault locator data are presented to operators. Of the users who responded to this question, approximately 58 percent (15 out of 26) provide these data on dynamically updated, dedicated EMS displays. None of the users employs dynamically updated, multi-purpose dashboard displays. The remainder of the users either have to dial up fault locator relays to obtain data or have support personnel obtain and pass along the information, i.e., in oral or written reports.

Fault locator data are narrowly used to facilitate restoration of an out-of-service facility. The data are not used to monitor system conditions in real time to maintain reliability or prevent or mitigate IROL or SOL violations. Therefore, RTBPTF does not recommend any new standards or requirements for fault locator information.

High-Speed Sampled Data

In general, survey results reveal that high-speed sampled data, such as sequence-of-events data and PMU data, are currently used primarily for post-event analysis rather than real-time operations. Approximately 40 percent (20 out of 51) of respondents use high-speed sampled data, and only about 39 percent (12 out of 31) of those who do not use this type of data plan to add it in the future. Only 2 of the respondents who use this type of data consider it ”essential” for situational awareness; 15 respondents consider these data ”desirable” for situational awareness. The following comments by survey respondents indicate the perceived value of high-speed sampled data:

> “Used as an assist in analysis of system problems.”
>
> “[Sequence of Events] data is not used by real-time operators, but by engineering staff for post-event analysis.”
>
> “Used for post event analysis.”
>
> “Enhances capabilities, but is not essential.”
>
> “[Respondent] is investigating ways of getting PMU data into real time.”

The survey also asked how high-speed sampled data are presented to operators. Of the users (18) who responded to this question, only 3 provide these data on dynamically updated, dedicated EMS displays or multi-purpose “dashboard” displays. Ten other users provide operators with written or on-line reports, and the others apparently provide the data only to engineering or other support staff.

High-speed sampled data are narrowly used for post-event analysis, not to monitor system conditions in real time to help maintain reliability or prevent or mitigate IROL or SOL violations. Therefore, RTBPTF does not recommend any new standards or requirements for these data. However, the task force notes that real-time application of PMU data is part of the scope of other industry initiatives such as the Eastern Interconnection Phasor Project,[26] and there is a placeholder in NERC's *Reliability Standards Development Plan: 2007-2009* for a new standard for PMUs. According to the NERC work plan, "Several industry studies were recently issued and these studies need to be analyzed to determine appropriate requirements for a NERC standard."[27]

Recommendations for New Reliability Standards

Currently, NERC Reliability Standards contain only two requirements related to weather data. Standard TOP-006-0, Monitoring System Conditions, has a requirement (R4) that "Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern." Also, Attachment 1 of Standard TOP-005-1, Operational Reliability Information, lists "severe weather" among the data that RCs, TOPs, and BAs are expected to provide to and share with one another. There are no measures for either of these requirements.

Recommendation – S6

Develop a new weather data requirement to situational awareness and real-time operational capabilities.

RTBPTF Recommendation

RTBPTF recommends[28] that a new requirement be added to Standard TOP-005-1 to address the importance of weather data for situational awareness and real-time operational capabilities.

PR1. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have dynamically updated real-time and forecasted weather data that are important to the operational capability and situational awareness of that particular entity so that operators can readily determine the current and near-term weather conditions that might affect monitoring or operation of their systems.

RTBPTF recommends the following measure for the requirement stated above:

PM1. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall document each type of weather data provided to operators and shall demonstrate the visualization tools or other means used to present these data to operators.

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[26] http://phasors.pnl.gov/

[27] *NERC Reliability Standards Development Plan: 2007-2009.* p. 210.

[28] Proposed requirements are designated "PR," and proposed measures are designated "PM."

Rationale

Real-Time Tools Survey results indicate that many respondents provide and use meteorological data for purposes other than forecasting load. Because meteorological data have become increasingly available in control centers and are commonly used to enhance situational awareness and support real-time operational capabilities, it is desirable and practical to “raise the bar” to ensure that all operators in all control centers have the weather information they need to do their jobs.

Weather varies considerably from region to region, and individual RCs, TOPs, and BAs tend to monitor the meteorological data that are most important to their specific needs. Therefore, the proposed requirement does not standardize the weather data to be collected but instead allows each entity to continue to determine which data are most important for its operators. Because a majority of survey respondents display weather data in a similar manner, using dynamically updated data on EMS displays or dashboard visualization or, at a minimum, commercial weather services available in the control center over cable television or the public Internet, mandating that operators receive dynamically updated real-time and forecasted data is consistent with prevailing practice.

Recommendations for Operating Guidelines

RTBPTF is not recommending Operating Guidelines related to Miscellaneous Data at this time.

Areas Requiring More Analysis

RTBPTF is not recommending additional areas for analysis related to Miscellaneous Data.

Examples of Excellence

RTBPTF did not identify any Examples of Excellence related to Miscellaneous Data.

Section 2.0
Reliability Tools for Situational Awareness

Introduction

RTBPTF formulated a list of real-time monitoring and analysis tools/applications commonly used by operators and inquired in the Real-Time Tools Survey about current industry practices associated with these tools.

The basis for the initial list was a report on minimum requirements and best practices for reliability software, presented at a FERC technical conference.[1] The report addressed the following functional areas:

- Network analysis
- Monitoring and visualization
- Real-time enablers
- Operations planning
- Transactions scheduling
- History and forecasting

RTBPTF first narrowed the scope of the list and limited the applications that the task force considered to real-time operator tools; that is, RTBPTF did not consider long-term, medium-term, day-ahead, and training tools even though these tools may be essential for reliability entities. The task force also did not consider real-time tools related to market or economic operations. Special emphasis was placed on real-time tools that could aid operator situational awareness (i.e., reliability tools) because the *Outage Task Force Final Blackout Report* repeatedly identifies operator situational awareness as a key element that needs improvement.

Next, RTBPTF used its collective expertise and experience to formulate a final list of tools to investigate and a precise definition for each. The Real-Time Tools Survey was designed so that different types of entities responsible for the reliable operation of the bulk electric system could describe their use of each tool, so the task force could use the survey results to characterize to the tool's status industry wide. The survey and the subsections below cover following real-time reliability tools for operators:

- **Section 2.1, Alarm Tools** — Alarm tools are applications that emit real-time visible and audible signals to alert operators to events and conditions affecting the state of the bulk electric system. Alarm tools

[1] Macedo, Frank. Consultant to FERC. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

can be external, embedded within the SCADA/EMS system, or a combination of both.

- **Section 2.2, Visualization Techniques** — Visualization techniques are a group of user interface applications, tools, and displays that provide, for operators and others, concise visual monitoring and enhanced multiple views of relevant power system data in real time. Visualization techniques help operators monitor and understand system events and/or conditions in neighboring power systems that may affect reliable operations in the operator's portion of the power system.
- **Section 2.3, Network Topology Processor** — The network topology processor (NTP) is a SCADA-based application that determines facility status and station configuration based on breaker and switch status data. The processor converts a nodal network model into a bus-branch model, for use by other applications such as the state estimator. It may perform the same function for study network applications such as power flow.
- **Section 2.4, Topology & Analog Error Detection** — Topology and analog error detection identifies and/or automatically overrides incorrect SCADA breaker and switch statuses, which can support the NTP application and to improve the accuracy and robustness of the state estimator application. It may also identify and/or automatically ignore SCADA analog measurements that are unreasonable or inconsistent with network connectivity.
- **Section 2.5, State Estimator** — The state estimator application performs statistical analysis using a set of imperfect, redundant, telemetered power system data to determine the system's current condition. The system condition or state is a function of several variables: bus voltages, relative phase angles, and tap changing transformer positions. A state estimator can typically identify bad analog telemetry, estimate non-telemetered flows and voltages, and determine actual voltage and thermal violations in observable areas. The state estimator application provides a base case for reliability-analysis applications and input to other system monitoring tools. The state estimator solution is typically used as the base case for other reliability-related applications, such as contingency analysis. In some cases, the state estimator is used primarily as the basis for information communicated to operators regarding power system status; e.g., the state estimator drives the alarm application that alerts operators to power system events.
- **Section 2.6, Contingency Analysis** — The contingency analysis application analyzes the impact on system security of specific, simulated outages (lines, generators, or other equipment) or higher

load, flow, or generation levels. Contingency analysis identifies problems such as line overloads or voltage violations that will occur if a new event (contingency) happens on the system. The state estimator solution is a representation of current system conditions and usually serves as the base case for contingency analysis. The information that contingency analysis generates enables RCs and TOPs to implement mitigation plans in advance of a contingent event such as a line trip. Contingency analysis is used as a real-time application as well as for studying potential scenarios.

- **Section 2.7, Critical Facility Loading Assessment (CFLA)** — A critical facility loading assessment (CFLA) evaluates a set of contingencies and then approximates the post-contingency loading of a set of monitored facilities using telemetered SCADA flows and line outage distribution factors (LODFs). CFLA may be used as a backup application if the state estimator and/or contingency analysis applications fail.
- **Section 2.8, Power Flow** — The power-flow application calculates the state of the electric power system in the form of flows, voltages, and angles, based on load, generation, net interchange, and facility status data. Power-flow applications are available in both on-line and off-line versions. An application that evaluates on-line power flow typically is incorporated into an EMS (or has a direct data feed from an EMS) and utilizes node-breaker topology whereas off-line power flow utilizes models of bus branches and static data. Section 2.8 addresses only on-line power flow.
- **Section 2.9, Study Real-Time Maintenance (SRTM)** — The SRTM function simulates real-time network applications (i.e., topology processor, state estimator, and contingency analysis) and debugs problems without affecting the real-time operation of the applications. An SRTM tool can be an on-line application integrated with the production EMS, an application integrated with a non-production EMS (development, test, dispatcher training simulator system, etc.), or an off-line application.
- **Section 2.10, Voltage Stability Assessment** — Voltage stability analysis (VSA) is an application that executes in near-real time and aids in the determination of system operating limits. VSA is based on an assessment that uses a current state estimator model of the real-time system. VSA may derive minimum voltages at key buses below which voltage collapse may occur under further stress to the system, evaluate whether sufficient stability margins exist for an analyzed base case, provide margins relative to particular stress modes such as transfers or system loading, or provide information on minimum dynamic reactive reserves required in local areas.

- **Section 2.11, Dynamic Stability Assessment —** Dynamic stability assessment (DSA) is an application (or suite of applications) executing in near-real time that aids in determining stability-related system operating limits using a current state estimator model of the real-time system. DSA may also indicate the dynamic stability margin for the most critical fault/contingency condition.
- **Section 2.12, Capacity Assessment —** The capacity assessment (or equivalent) application gives an overview of available generation capacity (MW or Mvar) in real time.
- **Section 2.13, Emergency Tools —** Emergency tools are applications or procedures that operators use when the power system enters or is about to enter an emergency. Several different types of emergency tools were considered in the Real-Time Tools Survey:
    - Residential Load Management or Residential Demand-Side Management tools, which allow curtailment of residential load demand for specific appliances
    - Commercial/Industrial Load Management or Commercial/Industrial Demand-Side Management tools, which allow curtailment of commercial/industrial load
    - Load Reduction by Voltage Reduction – curtailment of demand by voltage reduction on distribution loads
    - Rotating Load Shed – curtailment of demand by triggering/scheduling load shedding
- **Section 2.14, Other Tools (Current and Operational) —** This section reviews other tools (currently available and operational) that are not specifically addressed in the other sections. including:
    - Congestion Management Application - a tool for relieving network congestion within an entity’s service territory using operational means within the entity’s control authority, i.e., generation redispatch, curtailment of economy transactions within the entity’s service area, switching in capacitor banks, opening low-voltage lines. Typically, congestion management is a security-constrained dispatch program, an optimal power-flow program, or an heuristic program that searches for the best solution from a set of options. For an ISO or an RTO, this may be part of the locational marginal pricing (LMP) application.
    - Inter-Regional Real-Time Coordination for Congestion Management Application - may be different from the congestion management application listed above if the entity uses a separate tool for managing congestion caused by transactions that originate and/or terminate outside of the entity’s service area. This may also be the NERC Interchange Distribution

Calculator (IDC) if used for managing congestion that involves curtailing transactions outside of the entity's service territory.

- o Inter-Regional Real-Time Coordination for Market Redispatch – adjusts the market dispatch within the entity's service territory in coordination with adjacent reliability coordinators to manage inter-regional congestion in real time. This tool may be handled by the entity's congestion management application or through a different process.
- o Inter-Regional Voltage Profile Coordination — harmonizes the voltage profiles between two or more regions and may contain features such as wide-area voltage contour visualization, voltage schedule coordination between regions.
- o Short-Term Hydro Scheduling — manages, in real time, deviations from the long-term optimized schedule for reliability reasons (e.g., a response to a disturbance control standard event), acquiring support for localized voltage control.
- o Short-Term Wind Energy Forecasting — predicts and manages, in near-real time, generation accounting for variability of supply from wind energy sources.
- o Short-Term Load Forecasting — predicts short-term (next 0-60 minutes) loads based on parameters such as short-term weather effects, current load. Results could be used for predictive redispatch, look-ahead contingency analysis, awareness of scheduled non-conforming load changes, etc.
- o Short-Term Weather Forecasting — predicts short-term (next 0-60 minutes) extreme weather that may impact operations., i.e. lightning prediction tool, Doppler radar, etc.

Significance to the August 14, 2003 Blackout

The *Outage Task Force Final Blackout Report* concluded, and NERC concurred, that among the initiating causes of the 2003 blackout related to tools were:

- that FirstEnergy (FE) lost functionality of its critical monitoring tools and as a result lacked situational awareness of degraded conditions on its transmission system, and
- that the MISO RC did not provide adequate diagnostic support.

The *Outage Task Force Final Blackout Report* findings related to tools and operator situational awareness were the impetus for the formation of RTBPTF. The discussions of each tool that follows this introduction contain relevant background analysis and information from the *Outage Task Force Final Blackout Report*. For example, discussions that explain the directives given to FE and MISO related to the state estimator and contingency analysis are emphasized in the state estimator and contingency analysis sections below. The objective of these discussions is to introduce the reader to the significance of the RTBPTF recommendations as they relate to the *Outage Task Force Final Blackout Report* recommendations.

Tool Description and Usage

Each reliability tool (or set of tools) addressed in the Real-Time Tools Survey is described in detail in the following subsections. Each tool (or set of tools) is classified according to the industry's usage of it and its perceived importance for operator situational awareness. Most of the tools are commercially available and are generally used as intended. Discussions of each tool include the following:

- An assessment of the tool's availability within the respondent's organization (Is the tool available?)
- An assessment of the tool's usage (Is the tool operational?)
- An assessment of the tool's value for operator situational awareness and reliable operation of interconnected bulk electric system elements (How valuable is the tool for operators?)
- An assessment of the tool's general characteristics, algorithmic approaches, and functional features
- Description of available performance metrics for tool availability or tool solution quality (as applicable) and how they are assessed and used by survey respondents
- Description of the support and maintenance practices related to the tool

RTBPTF Recommendations for New Reliability Standards

RTBPTF approached each tool/application in the following way: given current NERC Reliability Standards how is the tool relevant in aiding operators in complying with monitoring and analysis requirements specified by the standards? Is the tool essential for operators to reliably manage the interconnected bulk electric system (i.e., should the tool be mandatory)?

Based on the survey results and current NERC Reliability Standards, RTBPTF recommends requiring the following monitoring and analysis tools for RCs and TOPs (illustrated in Figure 2.0-1 below):

- Alarm tools
- Telemetry data systems
- Network topology processor
- State estimator
- Contingency analysis

The rationale for recommending each tool as part of the minimum "Reliability Toolbox" is discussed in each of the tool's respective sections as well as in the Reliability Toolbox Rationale and Recommendation section near the beginning of this report. RTBPTF recommends requirements related to tool availability and solution quality (when applicable) for each of the mandatory tools listed above. RTBPTF believes that the mandatory tools listed above are essential for operators to maintain situational awareness and reliable operation of the bulk electric system. These essential tools are a mix of "monitoring" and "analysis" tools and are by no means the only tools that the operators that should use; RTBPTF believes that these are the *minimum* set of tools.

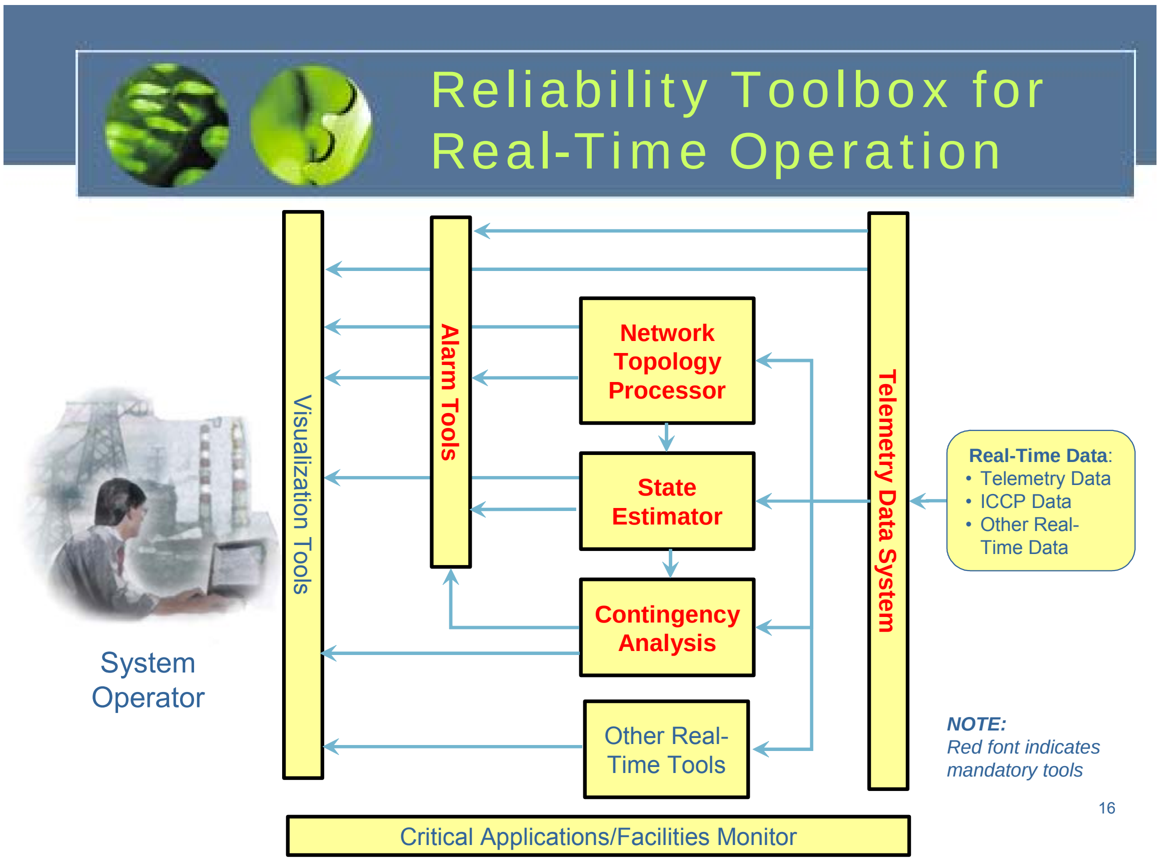

Figure 2.0-1 — The Reliability Toolbox

RTBPTF Recommendations for NERC Operating Guidelines

When there is a prevalent practice related to tool/application usage that supports a NERC Reliability Standard, a recommendation for Operating Guidelines is discussed in the relevant section of this report. In some cases, prevalent functional features that could aid operator situational awareness are recommended as Operating Guidelines.

Section 2.1
Alarm Tools

Definition

Alarm tools are applications that emit real-time visible and audible signals to alert operators to events and conditions affecting the state of the bulk electric system. Alarm tools can be external, embedded within the SCADA/EMS system, or a combination of both.

Background

The *Outage Task Force Final Blackout Report* stresses the importance of alarm tools, noting that “FE did not have additional or back-up monitoring tools to understand or visualize the status of their transmission system to facilitate its operators’ understanding of transmission system conditions after the failure of their primary monitoring/alarming systems.”[2]

The report analyzes FE’S computer problems in detail, with special emphasis on alarm tools. Excerpts of the analysis are quoted below:

> Starting around 14:14 [Eastern Daylight Time] EDT, FE’s control room operators lost the alarm function that provided audible and visual indications when a significant piece of equipment changed from an acceptable to a problematic condition. Shortly thereafter, the EMS system lost a number of its remote control consoles. Next it lost the primary server computer that was hosting the alarm function, and then the backup server such that all functions that were being supported on these servers were stopped at 14:54 EDT. However, for over an hour no one in FE’s control room grasped that their computer systems were not operating properly, even though FE’s Information Technology support staff knew of the problems and were working to solve them, and the absence of alarms and other symptoms offered many clues to the operators of the EMS system’s impaired state. Thus, without a functioning EMS or the knowledge that it had failed, FE’s system operators remained unaware that their electrical system condition was beginning to degrade. Unknowingly, they used the outdated system condition information they did have to discount information from others about growing system problems.[3]

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[2] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. page 18.
[3] Ibid., page 52.

Alarm tools are essential for reliability monitoring; operators rely heavily on audible and on-screen alarms as well as alarm logs to detect significant changes in system conditions. The *Outage Task Force Final Blackout Report* observes that alarms are the fundamental means by which operators identify bulk electric system events that need attention. Without alarms, operators may not detect events that signal significant system changes.[4] RTBPTF identifies alarm tools as critical real-time tools. The alarm tools section of the Real-Time Tools Survey attempted to obtain a snapshot of current industry availability and usage of alarm tools.

Summary of Findings

The survey results indicate that nearly all survey respondents have operational alarm tools and consider them "essential" for situational awareness although just over half of all respondents can detect and independently notify operators and support staff when alarm tools are not functioning. Other key results are that the three most widely used functional features of alarm tools are conditional alarming, multiple areas of responsibility, and independent alarm acknowledgment. Survey results also reveal that the failed alarm processor detection feature is not commonly available

As illustrated in Table 2.1-1, nearly all survey respondents (52 out of 53) report that their organizations have operational alarm tools and that these tools are "essential" for situational awareness (50 out of 52). However, fewer than 60 percent of all respondents can detect and independently notify operators and support staff when alarm tools are not functioning.[5]

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, "32/38=84%" means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

[4] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. page 52.

[5] The issue of awareness of availability of critical real-time tools is addressed in Section 5.4, Critical Applications Monitoring.

Survey Question	All	RCs	Others
Do you have Alarm Tools?	53/53 = 100%	17/17 = 100%	36/36 = 100%
Are these tools operational?	52/53 = 98%	17/17 = 100%	35/36 = 97%
Do you rate the value (essential) of your Alarm Tools application(s) as a reliability tool for situational awareness?	50/52 = 96%	17/17 = 100%	33/35 = 94%
Do you rate the value (desirable) of your Alarm Tools application(s) as a reliability tool for situational awareness?	2/52 = 4%	0/17 = 0%	2/35 = 6%
Do you rate the value (minimal value) of your Alarm Tools application(s) as a reliability tool for situational awareness?	0/52= 0%	0/17 = 0%	0/35 = 0%
Do you rate the value (no value) of your Alarm Tools application(s) as a reliability tool for situational awareness?	0/52 = 0%	0/17 = 0%	0/35 = 0%

Table 2.1-1 — Availability and Rating of Alarm Tools

Control room personnel are the primary users of alarm tools. However, first-line management and EMS support staff also use alarm tools at a majority of the respondents' locations. System protection and control personnel, field personnel, and systems security personnel use alarm tools at some respondents' locations.

The most common input to alarm tools comes from SCADA/EMS systems, but other applications also provide input. Table 2.1-2 summarizes the most common applications that interface with alarm tools.

What Applications Are Interfaced or Integrated With Your Alarm Tools?	All	RCs	Others
Topology processor	28/52 = 54%	12/17 = 71%	16/35 = 46%
State estimator	32/52 = 62%	12/17 = 71%	20/35 = 47%
Contingency analysis	31/52 = 60%	12/17 = 71%	19/35 = 54%
Artificial intelligence or other high-level summary applications	8/52 = 15%	4/17 = 24%	4/35 = 11%
Station one-line displays	46/52 = 88%	13/17 = 76%	33/35 = 94%
Other(s)	9/52 = 17%	4/17 = 24%	5/35 = 14%

Table 2.1-2 — Applications Typically Interfaced to Alarm Tools

The Real-Time Tools Survey asked respondents to identify their alarm tools' available functional features and to rank the value of each functional feature for situational awareness. Table 2.1-3 summarizes the responses. Blank percentages equal zero.

Functional Feature	All	Reliability Coordinator	Others
Conditional Alarming: Ability to define conditions before issuing an alarm. For example, you would only alarm on a circuit breaker change of state if another circuit breaker is also open.	Available: 28/51=55% Operational: 19/28=68%	Available: 10/17=59% Operational: 9/10=90%	Available: 18/34=53% Operational: 10/18=56%
	Essential: 10/19=53% Desirable: 9/19=47% Minimal: No Value:	Essential: 6/9=67% Desirable: 3/9=33% Minimal: No Value:	Essential: 4/10=40% Desirable:6/10=60% Minimal: No Value:
Paging/Beeping Feature: Ability for the Alarm Tools to trigger pager or automatic cell phone paging	Available: 20/50=40% Operational: 14/19=74%	Available: 7/17=41% Operational: 4/7=57%	Available: 13/33=39% Operational: 10/12=83%
	Essential: 8/14=57% Desirable: 3/14=21% Minimal: 1/14=7% No Value: 2/14=14%	Essential: 3/4=75% Desirable: 1/4=25% Minimal: No Value:	Essential: 5/10=50% Desirable: 2/10=20% Minimal:1/10=10% No Value: 2/10=20%
Multiple Areas of Responsibility: Ability for the Alarm Tools to alarm a single event and deliver it to multiple Operators or multiple areas of responsibility	Available: 41/50=82% Operational: 36/41=88%	Available: 16/17=94% Operational: 14/16=88%	Available: 25/33=76% Operational: 22/25=88%
	Essential: 26/36=72% Desirable: 9/36=25% Minimal: 1/36=3% No Value:	Essential: 10/14=71% Desirable: 4/14=29% Minimal: No Value:	Essential: 16/22=73% Desirable: 5/22=23% Minimal: 1/22=1% No Value:
Independent Alarm Acknowledgment: Ability for Operators from multiple areas of responsibility to acknowledge their alarms independently even if the alarm came from a single event	Available: 26/50=52% Operational: 21/26=81%	Available: 9/17=53% Operational: 8/9=89%	Available: 17/33=52% Operational: 13/17=76%
	Essential: 15/21=71% Desirable: 6/21=29% Minimal: No Value:	Essential: 6/8=75% Desirable: 2/8=25% Minimal: No Value:	Essential: 9/13=69% Desirable: 4/13=31% Minimal: No Value:
Intelligent Alarm Processor: Ability to summarize alarms based on multiple conditions in order to simplify presentation to the Operator and add understanding to the significance of the current situation	Available: 17/50=34% Operational: 14/16=88%	Available: 6/17=35% Operational: 5/6=83%	Available: 11/33=33% Operational: 9/10=90%
	Essential: 10/15=67% Desirable: 4/15=27% Minimal: 1/15=7% No Value:	Essential: 4/5=80% Desirable: 1/5=20% Minimal: No Value:	Essential: 6/10=60% Desirable: 3/10=30% Minimal: 1/10=10% No Value:
Failed Alarm Processor Detection: Ability to detect and independently notify operators and support staff that the alarm processor or Alarm Tools are down and not functioning	Available: 28/49=57% Operational: 27/28=96%	Available: 7/17=41% Operational: 7/7 100%	Available: 21/32=66% Operational: 20/21=95%
	Essential: 22/27=81% Desirable: 4/27=15% Minimal: 1/27=4% No Value:	Essential: 6/7=86% Desirable: 1/7=14% Minimal: No Value:	Essential: 16/20=80% Desirable: 3/20=15% Minimal: 1/20=5% No Value:
Alarm Help Feature: Ability to directly access response procedures from the alarms	Available: 12/49=24% Operational: 11/12=92%	Available: 5/17=29% Operational: 4/5=80%	Available: 7/32=22% Operational: 7/7=100%
	Essential: 3/11=27% Desirable: 8/11=73% Minimal: No Value:	Essential: 1/4=25% Desirable: 3/4=75% Minimal: No Value:	Essential: 2/7=29% Desirable: 5/7=71% Minimal: No Value:

Table 2.1-3 — Functional Features of Alarm Tools

Three functional features are most widely used and identified by most respondents as either “essential” or “desirable” for situational awareness:

- Conditional Alarming — This feature allows the tool to define conditions before issuing an alarm. Eighty-eight percent of respondents who have conditional alarming available use this feature. All users of this feature rate it “essential” (53 percent) or “desirable” (47 percent) for situational awareness.
- Multiple Areas of Responsibility — This feature allows the tool to deliver a single event alarm to multiple operators or multiple areas of responsibility. Sixty-eight percent of respondents who have the multiple areas of

responsibility feature available use it. Most users of this feature (72 percent) rate it “essential” for situational awareness.

- Independent Alarm Acknowledgment — This feature allows operators from multiple areas of responsibility to acknowledge alarms independently even if an alarm came from a single event. Sixty-eight percent of respondents who have the independent alarm acknowledgment feature available use it. Most users of this feature (71 percent) rate it “essential” for situational awareness.

It is somewhat surprising to note that the failed alarm processor detection feature is not commonly available despite the *Outage Task Force Final Blackout Report*’s implicit recognition of the importance of this feature. Most respondents who have this feature available rate it “essential” for situational awareness (81 percent). This functionality is discussed further in Section 5.4, Critical Applications Monitoring.

Recommendations for New Reliability Standards

Alarm tools are essential, providing visual and audible signals in real time to alert operators and others to events affecting the state of the bulk electric system. Alarms may be initiated by information transmitted directly from telemetry data systems or from other applications, such as the state estimator and contingency analysis. Alarms are an essential means of conveying situational awareness to operators. Accordingly, RTBPTF recommends modifications to existing standards to clarify that use of these tools is mandatory (see the Reliability Toolbox Rationale and Recommendation section). The discussions below support RTBPTF’s recommendation to make alarm tools mandatory.

Recommendation – S1

Mandate the following reliability tools as mandatory monitoring and analysis tools

- Alarm Tools
- Telemetry Data Systems
- Network Topology Processor
- State Estimator
- Contingency Analysis

Alarm Tools: Mandatory Monitoring and Analysis Tool

The *Outage Task Force Final Blackout Report* succinctly states the importance of alarm tools:[6]

[6] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. page 52.

Alarms are a critical function of an EMS, and EMS-generated alarms are the fundamental means by which system operators identify events on the power system that need their attention. Without alarms, events indicating one or more significant system changes can occur but remain undetected by the operator. If an energy management system's alarms are absent, but operators are aware of the situation and the remainder of the its functions are intact, the operators can potentially continue to use the EMS to monitor and exercise control of their power system. In such circumstances, the operators would have to do so via repetitive, continuous manual scanning of numerous data and status points located within the multitude of individual displays available within their EMS. Further, it would be difficult for the operator to identify quickly the most relevant of the many screens available.

Existing NERC reliability standards implicitly assume the use of alarm tools to aid RCs and TOPs in maintaining situational awareness for the bulk electricity system. Specifying alarm tools as part of the Reliability Toolbox[7] eliminates the vagueness in current NERC reliability standards regarding whether alarm tools, as defined, are mandatory.

Recommendation – S7

Specify and measure minimum availability for alarm tools

Alarm tools availability

If alarm tools are mandatory for bulk electric system situational awareness, they must be highly available and redundant. Awareness of alarm tools availability is discussed in the recommendations in Section 5.4, Critical Applications Monitoring. However, a more detailed awareness (via a requirement for alarm tools availability) of alarm tools is necessary than is described in Section 5.4; in particular, awareness of any "stalled" state is critical. The *Outage Task Force Final Blackout Report* states, "[a]fter that time, the FE control room consoles did not receive any further alarms, nor were there any alarms being printed or posted on the EMS's alarm logging facilities. Power system operators rely heavily on audible and on-screen alarms, plus alarm logs, to reveal any significant changes in their system's conditions. After 14:14 EDT on August 14, FE's operators were working under a significant handicap without these tools. However, they were in further jeopardy because they did not know that they were operating without alarms, so that they did not realize that system conditions were changing."[8]

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[7] See the Reliability Tool Box Rationale and Recommendation section.
[8] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. page 52.

RTBPTF recommendation

RTBPTF recommends adding the following new requirement to Standard TOP-006 in order to measure alarm tools availability:

PR1. Alarm Tools Availability. Each reliability coordinator and transmission operator shall operate its alarm tools such that the alarm tools shall have at least one test alarm (or "watchdog" alarm) generated and processed at the Telemetry Data System scan rate. This test alarm (or "watchdog" alarm) could originate from a test field device or could be application generated.

Although the NERC standards process might address other factors in considering this recommendation, RTBPTF recommends the following measure for the requirement stated above:

PM1. Each reliability coordinator and transmission operator shall maintain alarm logs demonstrating that the responsible entity's alarm tools application processed test alarms ("watchdog" alarms) according to Requirement PR2.

Rationale

Analysis of the alarm problem encountered by FE during the 2003 blackout suggests that FE's alarm tools essentially "stalled" while processing alarm events; that is, the alarm tools failed to complete the processing of alarms or produce any other valid output. In the meantime, new inputs — system condition data that needed to be reviewed for possible alarms — built up in and then overflowed the input buffers of the process.[9]

RTBPTF believes that a requirement should be established to correct the situation described above; specifically, an alarm tools availability metric should be required to complement the recommendations in Section 5.4, Critical Applications Monitoring.

Recommendation – G1

Identify implementation strategies and specific algorithms for conditional alarming.

Recommendations for New Operating Guidelines

Based on the survey results, three alarm tools features are most commonly used and identified by most respondents as "essential" or "desirable" for situational

[9] Ibid, Pages 53–54.

awareness. Because one of these features, conditional alarming, could easily be implemented similarly by different entities, "rules" for conditional alarming could be included in an operating guideline. The operating guideline for conditional alarming should identify implementation strategies and specific algorithms that could improve the alarms being sent to operators. The "rules" for conditional alarming need to be determined by studying prevailing industry practices before any operating guidelines are set for alarm tools.

The other two commonly used alarm tools features (multiple areas of responsibility and independent alarm acknowledgment) would most likely be customized to the needs of each entity, so a general operating guideline would be of little or no value. The implementation of these features would vary widely depending on the implementation of areas of responsibility of an entity.

Recommendation – A3

Study intelligent alarm processing capability for producing a single accurate view of system status.

Areas Requiring More Analysis

Macedo (2004)[10] identifies as a minimum requirement for alarm tools intelligent alarm processing that allows the application to filter, prioritize, and group alarms. RTBPTF perceives filtering, prioritization, and grouping of alarms as essential features that are inherent in industry-wide tools as defined in this section and understands intelligent alarm processing as an advanced feature that uses algorithms (i.e. artificial intelligence, neural networks) to process raw alarms and identify root causes of alarm avalanches. This functional feature produces compact, simplified alarm information for operators. RTBPTF recommends additional analysis of the industry's intelligent alarm processing capability because survey results indicate that this seemingly essential feature is not commonly used.

The conditional alarming feature could be classified as an elementary form of intelligent alarm processing. As noted above, intelligent alarm processing allows the tool to summarize alarms based on multiple conditions to simplify presentation to the operator and clarify the significance of a current situation. Depending on the level of complexity of monitoring of entity's area of responsibility, a feature such as intelligent alarm processing could aid operators in timely assessment of and response to complex situations. Processed alarms could give operators a single accurate view of system status so that they would

[10] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

not have to sift through numerous alarms simultaneously. Intelligent alarm processing is currently in use (34 percent of the Real-Time Tools Survey participants have this feature available). A barrier to wide use of this feature could be the difficulty of setting it up (i.e., the difficulty of maintaining the intelligent database of event processing as underlying system topology is modified). RTBPTF proposes that research in the area of intelligent alarm processing be conducted as the basis for practical implementation of this feature by the industry.

Examples of Excellence

The RTBPTF did not identify any Examples of Excellence related to alarm tools.

Section 2.2
Visualization Techniques

Definition

Visualization techniques are a group of user interface applications, tools, or displays that provide concise visual monitoring and enhanced multiple views of relevant power system data in real time to operators and others. Visualization techniques help an operator monitor and understand system events and/or conditions across neighboring power systems that may be affecting reliable operations in the operator's portion of the power system.

Background

The purpose of the visualization techniques section of the Real-Time Tools Survey was to determine typical industry practices or implementation by RCs, TOPs, and BAs of operational visualization tools. The survey attempted to obtain a snapshot of the current state of the industry regarding the availability and usage of certain types of visualization tools. The survey gave special emphasis to the types of visualization tools available to view/monitor bulk electric system elements currently used by reliability entities.

This section of the report summarizes findings from the Real-Time Tools Survey concerning visualization tools. The objective of this summary is to identify the visualization tools that are in wide use and their functionalities. This section also addresses the definition of the terms "wide area" and "wide area view" in the context of existing NERC reliability standards.[11] RTBPTF introduces the concept of the "view-area view boundary," defined as the network model boundary for the "wide area." The task force recommends that NERC establish a uniform formal process to define what constitutes bulk electric system elements included in the "wide area" and corresponding processes to define the "wide area view boundary."

RTBPTF recommends specific modifications to existing IRO and TOP reliability standards that require the use of visualization tools as part of compliance measures for existing NERC reliability standards. RTBPTF also recommends areas requiring further analysis related to the use, technology forums, and development of visualization tools for operators.

Visualization Tools and the 2004 Blackout

The *Outage Task Force Final Blackout Report* concludes that the August 14, 2003 blackout was similar in many ways to previous large-scale blackouts. The

[11] "Wide area" is defined in the NERC Glossary, which can be found at: http://www.nerc.com.

2003 blackout repeated many deficiencies identified in studies of prior large-scale blackouts, including poor vegetation management and operator training practices and a lack of adequate tools to allow operators to visualize system conditions.

The report states that the principal cause of the August 14, 2003 blackout was a lack of situational awareness, which was, in turn, the result of inadequate reliability tools and backup capabilities. The need for improved visualization capabilities over a wide geographic area is a recurrent theme in the blackout investigation. The report also notes that some wide-area tools to aid situational awareness (i.e., real-time phasor measurement systems) have been tested in some regions but are not yet in general use. Improvements in this area will require significant new investments involving existing or emerging technologies.

In the *Outage Task Force Final Blackout Report*, causal analysis of the blackout concludes that FE lacked situational awareness of transmission-line outages and degraded conditions on its own power system. This lack of situational awareness prevented FE system operators from taking corrective actions to return the system to within limits and from notifying MISO and neighboring systems of the degraded system conditions and loss of critical functionality in the control center. One cause for the lack of situational awareness was attributed to FE operators not having an effective alternative by means of which they could easily visualize the overall conditions of the system once their alarm tools application failed. An alternative for readily visualizing overall system conditions, including the status of critical facilities, would have enabled FE operators to become aware of forced transmission-line outages in a timely manner even though the alarms were non-functional. The report also indicates that MISO did not have monitoring tools that provided high-level visualization of the system. A high-level monitoring tool would have enabled MISO operators to view degrading conditions in the FE power system. A dynamic mapboard or other type of display could have provided a system status overview that could have been quickly and easily understood by the operators of both entities.

Chapter 10 of *Outage Task Force Final Blackout Report* presents recommendations to prevent or minimize the scope of future blackouts. The report identifies direct causes and contributing factors that include "inadequate regional-scale visibility over the bulk power system[12] and recommends that NERC evaluate and adopt better real-time tools for operators and reliability coordinators (Recommendation 22). The report further recommends that NERC require that its operating committee give particular attention in its report to the development of guidance to BAs and RCs on the use of automated wide-area visualization display systems and the integrity of data used in those systems. The report identifies a need for improved visualization techniques and intelligent software to analyze conditions, prioritize issues, and recommend actions. These

[12] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April. p. 140

technologies should address some of the human factor issues that currently affect control room operators.[13]

Summary of Findings

The survey results indicate that most respondents use visualization tools and consider them essential for situational awareness, but that practice and implementation of visualization tools vary.

The description of findings below addresses the different visualization tools that were reported in the survey.

The results of the Real-Time Tools Survey reveal varying degrees of practice and implementation related to visualization tools. Use of visualization tools is prevalent in the industry (96 percent of the respondents indicated that they have some form of visualization tools), as shown in Table 2.2-1.

Respondent Type	Percentage That Have Visualization Tools Available
All	47/49=96%
RC	17/17=100%
Others	30/32=94%

Table 2.2-1 — Availability of Visualization Tools

As illustrated in Table 2.2-2, the majority of respondents (46/47=98 percent) indicated that they have an operational visualization tools application. Respondents having an operational visualization tools application were asked about the value of their respective visualization tools application as a reliability tool for situational awareness.

[13] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 159

Respondent Type	Percentage That Have Operational Visualization Tools	Value Placed on Visualization Tools for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	46/47=98%	38/46=83%	8/46=17%
RC	16/17=94%	15/16=94%	1/16=6%
Others	30/30=100%	23/30=77%	7/30=23%

Table 2.2-2 — Usage and Value of Visualization Tools by Entity Type

The majority of respondents that reported that they have operational visualization tools rated the value of their tools in enhancing situational awareness as either "essential" (83 percent) or "desirable" (17 percent). One respondent commented, "[c]lear concise information is mandatory for proper operator response." There are various types of visualization tools in use by reliability entities to monitor bulk electric system elements and parameters. Visualization tools allow operators to avoid directly viewing large amounts of raw data (telemetry or other real-time reliability tool/application-type data) directly so that operators can efficiently respond to power system problems. Visualization tools organize critical reliability parameters, which allow operators to monitor the information more efficiently.

The methods that visualization tools use to process and display critical reliability parameters depend on information resulting from the processing of raw data. The Real-Time Tools Survey inquired about certain types of visualization tools but did not by any means include a comprehensive list of the different types of visualization tools available to operators. Respondents were also given a chance to describe their own versions of visualization tools if their tools did not fit in any of the types specified in the survey and if their own versions of the tool were worth noting as an example of excellence.

According to the survey results, the data most commonly used by visualization tools are SCADA-type (i.e., telemetry data) data, followed by state estimator-type data. Respondents identified the following types of visualization tools:

- SCADA one-line displays
- State estimator one-line displays
- Study area one-line displays
- Dynamic overview displays
- Dynamic mapboards
- Wide-area visualization tools
- Selectable data trending

- Reactive reserve monitors[14]
- Remedial action scheme (RAS) monitors
- Automatic safety nets
- Transaction impact monitors
- Flowgate monitors

These types of visualization tools are described and discussed in the subsections below.

SCADA One-Line Displays

SCADA one-line displays are dynamic, one-line diagram displays of substations and major power system components that present the real-time status and selected flow, voltage, and other power system data. This is the most common type of visualization tool used today to monitor bulk electric system elements or parameters. Most entities (98 percent) having operational SCADA one-line displays rate this type of visualization tool "essential" (98 percent) for enhancing situational awareness. Table 2.2-3 summarizes the survey results for SCADA one-line displays by respondent type.

Respondent Type	Percentage That Have Operational SCADA One-Line Displays	Value of SCADA One-Line Displays for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	47/48=98%	46/47=98%	1/47=2%
RC	16/16=100%	16/16=100%	0/16=0%
Others	31/32=97%	30/31=97%	0/31=0%

Table 2.2-3 — Usage and Value of SCADA One-Line Displays by Respondent Type

The majority of respondents (91 percent) noted that their operators view SCADA one-line displays using proprietary SCADA/EMS terminals. Although not as prevalent, web-based SCADA one-line displays, either through a limited private network (28 percent) or through the entity's corporate intranet (19 percent), provide an alternative method of viewing SCADA one-line displays. SCADA/EMS support staff construct most SCADA one-line displays manually using a display editor (91 percent); a minority of entities (17 percent) use

[14] The original name for this type of visualization tool (per the Real-Time Tools Survey) was "Dynamic Reactive Reserve Monitoring" although the intent of this type of visualization was to monitor both dynamic and static sources. Therefore, to eliminate confusion, RTBPTF changed the name of this tool to "reactive reserve monitor" throughout this report.

applications that auto-generate the SCADA one-line displays using a vendor-provided default format.

The survey results indicate that SCADA one-line displays also have the following prevalent characteristics:

- Status values can be overridden by the operator through these displays.
- Analog values can be overridden by the operator through these displays
- Dynamic coloring is used for 1) indicating points in the alarms, 2) switching device positions, 3) indicating bus, line, and transformer statuses, and 4) indicating equipment clearance tags.
- Links are used to navigate to the master index or other one-line displays.
- The displays show SCADA quality codes on status and analog points.
- Although this feature is not as common, important procedures can be linked to selected displays.

Various Types of SCADA One-Line Displays

The survey asked respondents to quantify the relative number (“all,” “most,” “some,” or “none”) of SCADA one-line displays that are available for stations within the respondent’s area of responsibility. There are various types of SCADA one-line displays (including summary displays that use SCADA data), and the survey asked respondents to quantify each type. Table 2.2-4 summarizes the responses for each type of display. The responses indicate the most common types of SCADA one-line displays currently used across the industry. The results correlate to the availability of telemetry data (see Section 1.1) needed for the type of SCADA one-line display.

Type of SCADA One-Line Display	What One-Line Displays are Available for Stations Within Your Area of Responsibility?			
	All	Most	Some	None
SCADA one-line for substations connected at 345-765 kV	38/43=88%			5/43=12%
SCADA one-line for substations connected at 100-230 kV	41/45=91%	4/45=9%		
SCADA one-line for substations connected at below 100 kV	21/46=46%	16/46=35%	7/46=15%	2/46=4%
Summary display(s) showing important flow gates at all substations	21/42=50%	3/42=7%	6/42=14%	12/42=29%
SCADA one-line for generation plants connected at 345-765 kV	36/42=86%			6/42=14%
SCADA one-line for generation plants connected at 100-230 kV	42/45=93%	1/45=2%	1/45=2%	1/45=2%
SCADA one-line for generation plants connected at below 100 kV	32/46=70%	8/46=17%	4/46=9%	2/46=4%
Summary display(s) showing generation from all sources in the area	32/46=70%	9/46=20%	3/46=7%	2/46=4%
Summary display(s) showing switched reactive devices from all sources	33/46=72%	7/46=15%	4/46=9%	2/46=4%

Table 2.2-4 — Summary of Responses — Relative Number of SCADA One-Line Displays Available for Stations Within Respondents’ Areas of Responsibility

Table 2.2-5 illustrates the results for RCs, which are relatively similar to those from the general population.

Type of SCADA One-Line Display	What One-Line Displays are Available for Stations Within Your Area of Responsibility?			
	All	Most	Some	None
SCADA One-Line for Substations Connected at 345-765 kV	15/15=100%			
SCADA One-Line for Substations Connected at 100-230 kV	14/16=88%	2/16=13%		
SCADA One-Line for Substations Connected at below 100 kV	6/16=38%	5/16=31%	4/16=25%	1/16=/6%
Summary display(s) showing important flow gates at all substations	9/16=56%	3/16=19%	2/16=13%	2/16=13%
SCADA One-Line for Generation Plants Connected at 345-765 kV	15/15=100%			
SCADA One-Line for Generation Plants Connected at 100-230 kV	15/16=94%		1/16=6%	
SCADA One-Line for Generation Plants Connected at below 100 kV	12/16=75%	2/16=13%=	2/16=13%	
Summary display(s) showing generation from all sources in the area	12/16=75%	2/16=13%=	1/16=/6%	1/16=6%
Summary display(s) showing switched reactive devices from all sources	10/16=63%	2/16=13%	3/16=19%	1/16=6%

Table 2.2-5 — Summary of Responses — Relative Number of SCADA One-Line Displays Available for Stations within the RC's Area of Responsibility

Respondents were also asked to quantify the relative number of SCADA one-line displays available for stations in the areas adjacent to the respondent's area of responsibility. There are various types of SCADA one-line displays, including summary displays; entities were asked to quantify each type. Table 2.2-6 summarizes the responses for each type. Overall, there are fewer representations of bulk electric system elements on SCADA one-line displays of the areas adjacent to respondents' areas of responsibility compared to representations of locations within respondents' areas of responsibility. Table 2.2-7 summarizes the data for RCs.

Type of SCADA One-Line Display	What One-Line Displays are Available for Stations in the Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
SCADA one-line for substations connected at 345-765 kV	11/43=26%	5/43=12%	20/43=47%	7/43=16%
SCADA one-line for substations connected at 100-230 kV	6/44=14%	6/44=14%	26/44=59%	6/44=14%
SCADA one-line for substations connected at below 100 kV	4/44=9%	4/44=9%	13/44=30%	23/44=52%
Summary display(s) showing important flow gates at all substations	5/41=12%	5/41=12%	10/41=24%	21/41=51%
SCADA one-line for generation plants connected at 345-765 kV	11/44=25%	3/44=7%	14/44=32%	16/44=36%
SCADA one-line for generation plants connected at 100-230 kV	7/44=16%	6/44=14%	17/44=39%	14/44=32%
SCADA one-line for generation plants connected at below 100 kV	6/45=13%	1/45=2%	14/45=31%	24/45=53%
Summary display(s) showing generation from all sources in the area	5/44=11%	5/44=11%	5/44=11%	29/44=66%
Summary display(s) showing switched reactive devices from all sources	6/44=14%		6/44=14%	32/44=73%

Table 2.2-6 — Summary of Responses — Relative Number of SCADA One-Line Displays Available for Stations in Areas Adjacent to Respondents' Areas of Responsibility

Type of SCADA One-Line Display	What One-Line Displays are Available for Stations in the Areas Adjacent to Your Area of Responsibility?			
	All	Most	Some	None
SCADA One-Line for Substations Connected at 345-765 kV	5/14=36%	3/14=21%	5/14=36%	1/14=7%
SCADA One-Line for Substations Connected at 100-230 kV	2/14=14%	4/14=29%	7/14=50%	1/14=7%
SCADA One-Line for Substations Connected at below 100 kV	2/14=14%	1/14=7%	3/14=21%	8/14=57%
Summary display(s) showing important flow gates at all substations	4/14=29	2/14=14%	6/14=43%	2/14=14%
SCADA One-Line for Generation Plants Connected at 345-765 kV	7/15=47%	2/15=13%	5/15=33%	1/15=7%
SCADA One-Line for Generation Plants Connected at 100-230 kV	6/15=40%	3/15=20%	5/15=33%	1/15=7%
SCADA One-Line for Generation Plants Connected at below 100 kV	4/15=27%	1/15=7%	5/15=33%	5/15=33%
Summary display(s) showing generation from all sources in the area	2/15=13%	3/15=20%	3/15=20%	7/15=47%
Summary display(s) showing switched reactive devices from all sources	2/15=13%		4/15=27%	9/15=60%

Table 2.2-7 — Summary of Responses — Relative Number of SCADA One-Line Displays Available for Stations in Areas Adjacent to RC's Area of Responsibility

Various Types of Data Displayed on SCADA One-Line Displays

Respondents were asked to quantify the relative numbers of the types of data shown in their SCADA one-line displays for stations located within their area of responsibility. Various types of data are linked to SCADA one-line displays; respondents were asked to quantify the relative number of each data type. Table 2.2-8 summarizes the responses for each data type. The responses indicate the most common types of data linked to SCADA one-line displays across the industry. Breaker statutes and transmission MW/Mvar flows are the most common types of data shown in typical SCADA one-line displays.

Type of Data Displayed in SCADA One-Line Display	What Types of Data are Displayed on One-Line Displays for Stations Located Within Your Area of Responsibility?			
	All	Most	Some	None
Telemetered Breaker/Switch Position (open/close)	35/46=76%	11/46=24%		
Non-telemetered Breaker/Switch Position (open/close)	25/44=57%	18/44=41%		1/44=2%
Bus Voltage Magnitudes	25/46=54%	21/46=46%		
Bus Voltage Phase Angles	2/42=5%	4/42=10%	8/42=19%	28/42=67%
Line End Voltages (synchronizing potential on open line)	12/45=27%	10/45=22%	18/45=40%	5/45=11%
Ampere Flow on Lines and Transformers	13/44=30%	8/44=18%	11/44=25%	12/44=27%
Ampere Flow on Switching Devices	4/44=9%	6/44=14%	17/44=39%	17/44=39%
MW and Mvar flow On Lines and Transformers	22/46=48%	23/46=50%	1/46=2%	
Thermal and Voltage Operating Limits/Ratings	15/45=33%	9/45=20%	6/45=13%	15/45=33%
Incidental Station Alarms (entry, battery, transformer temperature, etc)	11/46=24%	12/46=26%	7/46=15%	16/ 46=35%

Table 2.2-8 — Summary of Responses — Types of data in SCADA One-Line Displays for Stations within Respondents' Areas of Responsibility

State Estimator One-line Displays

State estimator one-line displays are dynamic, one-line diagram displays of substations and major system components that present the state estimator solution for status and selected flow, voltage, and other power system data. Seventy-two percent of respondents have operational state estimator one-line displays. Respondents that have operational state estimator one-line displays rate this type of visualization tool either as “essential” (62%) or “desirable” (38%) for situational awareness. Table 2.2-9 summarizes the results of the survey for one-line displays by entity type. Most respondents view state estimator one-line displays using proprietary SCADA/EMS terminals, and most state estimator one-line displays are constructed from the existing SCADA one-line displays or manually by EMS support staff.

Respondent Type	Percentage That Have Operational State Estimator One-Line Displays	Value of State Estimator One-Line Displays for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	33/46=72%	18/29=62%	11/29=38%
RC	16/16=100%	12/16=75%	4/16=25%
Others	17/30=57%	6/13=46%	5/14=36%

Table 2.2-9 — Usage and Value of the State Estimator One-Line Displays by Respondent

The survey results indicate that state estimator one-line displays have the following prevalent characteristics:

- Status values can be overridden by the operator through these displays.
- Analog values can be overridden by the operator through these displays.
- Some entities link the state estimator residual values on their state estimator one-line displays.
- Dynamic coloring is used for 1) indicating points in alarm, 2) switching device positions, and 3) indicating bus, line, and transformer statuses.
- Links are used to navigate to the master index or other one-line displays.
- The displays show SCADA quality codes on status and analog points as processed by the state estimator.
- Although this feature is not as common, important procedures are linked to selected displays

Study Area One-line Displays

Study area one-line displays are one-line diagram displays of substations and major system components that present the active study context[15] of status and selected flow, voltage, and other data from the power system model in use. Examples of this type of visualization tool are power-flow one-line displays and contingency analysis one-line displays (for a specified contingency). Seventy-three percent of respondents have operational study area one-line displays. Respondents that have operational study area one-line displays rate this type of visualization tool as either "essential" (70 percent) or "desirable" (30 percent) for situational awareness. Table 2.2-10 summarizes the survey results of for study area one-line displays, by respondent type.

[15] Study context pertains to the output solution of certain power system network applications such as power flow, contingency analysis, etc.

Respondent Type	Percentage That Have Operational Study Area One-Line Displays	Value of Study Area One-Line Displays for Enhancing Situational Awareness	
		"Essential"	**"Desirable"**
All	32/44=73%	21/30=70%	9/30=30%
RC	16/16=100%	12/16=75%	4/16=25%
Others	16/28=57%	9/14=64%	5/14=36%

Table 2.2-10 — Usage and Value of Study Area One-Line Displays by Respondent Type

Study area one-line displays have these prevalent characteristics:

- Study context status values can be changed by the operator through these displays.
- Study context analog values can be changed by the operator through these displays
- Study context solution can be executed by the operator from these displays.
- Dynamic coloring is used for 1) indicating points in alarm, 2) switching device positions, and 3) indicating bus, line, and transformer statuses.
- Links are used to navigate to the master index or other one-line displays.

Dynamic Overview Displays

Dynamic overview displays are one-line and other graphical displays depicting the state, loading, and/or voltage levels over the wider area (or a sub-area within the entity's internal footprint) of the power system. Dynamic overview displays are essentially large SCADA one-line displays. An example of this type of visualization tool is area overview one-line displays, a one-line display that shows a group of electrically connected substations for a specified area. Eighty-two percent of respondents have operational dynamic overview displays. Respondents rate this type of visualization tool as "essential" (56 percent), "desirable" (42 percent), or of "minimal value" (3 percent) for situational awareness. Table 2.2-11 reflects the survey results for dynamic overview displays, by respondent type.

Respondent Type	Percentage That Have Operational Dynamic Overview Displays	Value of Dynamic Overview Displays for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	36/44=82%	20/36=56%	15/36=42%
RC	16/16=100%	9/16=56%	7/16=44%
Others	20/28=71%	11/20=55%	8/20=40%

Table 2.2-11 —Usage and Value of Dynamic Overview Displays by Respondent Type

Dynamic overview displays have these prevalent characteristics:

- Layered zooming with automatic de-cluttering
- Animated power flow (magnitudes and direction)
- Dynamic coloring for indicating real-time bus, line, and transformer status
- Navigational links to the master index or one-line displays
- Availability for telemetered (SCADA) output
- Continuous projection or display in large format for system operators
- Inclusion of boundary substations/plants adjacent to entity's area of responsibility

The survey asked respondents to quantify the relative number of power system elements (within the entity's area of responsibility) displayed in their dynamic overview displays. Table 2.2-12 summarizes the responses. The responses indicate the level of detail of dynamic overview displays across the industry.

Power System Element	What Power System Elements Within Your Area of Responsibility are Displayed on the System Overview?			
	All	Most	Some	None
Lines operating at 345-765 kV	28/33=85%	2/33=6%	1/33=3%	2/33=6%
Lines operating at 100-230 kV	24/35=69%	6/35=17%	5/35=14%	
Lines operating at below 100 kV	9/35=26%	8/35=23%	5/35=14%	13/35=37%
Transmission level intertie transformer banks	14/34=41%	5/34=15%	7/34=21%	8/34=24%
Transmission level capacitor/reactor banks	19/35=54%	5/35=14%	3/35=9%	8/35=23%
Generation plants 500 MW	24/33=73%	3/33=9%	2/33=6%	4/33=12%
Generation plants 100-500 MW	25/35=71%	2/35=6%	4/35=11%	4/35=11%
Generation plants < 100 MW	16/34=47%	6/34=18%	6/34=18%	6/34=18%
Substation switching devices on lines and transformers	7/33=21%	9/33=27%	8/33=24%	9/33=27%
Substation bus voltages	11/35=31%	18/35=51%	6/35=17%	
Line and transformer flows (MW and MVAR)	9/35=26%	20/35=57%	5/35=14%	1/35=3%

Table 2.2-12 — Summary of Responses — Type of Power System Element included in Dynamic Overview Displays

Dynamic Mapboard

A dynamic mapboard is a stationary, prominently located physical collection of painted lines, status lights, and analog readouts presenting continuous real-time status of important selected components of the power system to operators. It is "dynamic" because the status data for important selected components of the power system are updated in real time. A dynamic mapboard usually complements common SCADA/EMS displays. Sixty-five percent of survey respondents report that they have a dynamic mapboard and rate this type of visualization tool as "essential" while an additional 35 percent rate it "desirable" for enhancing situational awareness. Table 2.2-13 summarizes the survey results for the dynamic mapboard by respondent type. The Real-Time Tools Survey did not ask any questions regarding the extent of the entity's footprint displayed using the dynamic mapboard.

Some respondents indicated in comments that, in lieu of a dynamic mapboard, they use video projection technology (see wide-area visualization tools below) to show the same type of information to their operators.

Respondent Type	Percentage That Have Operational Dynamic Mapboard	Value of Dynamic Mapboard for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	28/43=65%	17/26=65%	9/26=35%
RC	10/15=67%	5/8=63%	3/8=38%
Others	18/28=64%	12/18=55%	6/18=33%

Table 2.2-13 — Usage and Value of Dynamic Mapboard by Respondent Type

A dynamic mapboard has these prevalent characteristics:

- Mosaic structure for easy accommodations of revisions/changes
- Color/lighting dynamics indicating breaker/switch status
- Digital readouts for presenting critical voltage or flow information
- Availability for telemetered output
- Maintenance of last known state/values if data link and/or SCADA/EMS fails
- Inclusion of boundary substations/plants adjacent to entity's area of responsibility

Wide-Area Visualization Tools

Wide-area visualization tools consist of displays/tools driven by SCADA, EMS, PMU, disturbance recorder, and other technical data collected in real time that present concise information for the "wide area." In general, these display/tools show multiple views of the status of critical facilities within the entity's internal footprint, but they are also used to show views of critical facilities or data from the entity's external footprint that have the potential to adversely impact the internal system (i.e., they cover the "wide area" as defined by the NERC Glossary, which can be viewed at: http://www.nerc.com). Under this definition, dynamic overview displays may be considered wide-area visualization tools. In addition to the traditional SCADA/EMS displays that show critical reliability parameters, wide-area visualization tools use other forms of technology/methodology to present vast amounts of information in a form that allows the operator to quickly and intuitively assess the state of the system. Examples of wide-area visualization technology/techniques include:

- Video or other forms of "big screen" or projection technology (usually in lieu of a traditional dynamic mapboard)
- Smart dashboards (i.e., wide-area status summary displays that show composite data from various applications/tools)
- Displays with extensive animation (i.e., line-flow visualization)[16]
- Contour displays (used to show spatially distributed continuous data)
- Virtual environment visualization[17]
- Data-mining systems[18]

Fifty-two percent of respondents report that they have wide-area visualization tools and rate these tools as either "essential" (55 percent) or "desirable" (45 percent) for enhancing situational awareness. Table 2.2-14 summarizes the survey results for wide-area visualization tools by respondent type.

[16] See http://www.pserc.wisc.edu/ecow/get/publicatio/1999public/etrep05Smaller.pdf
[17] Ibid.
[18] See http://www.infres.enst.fr/~hebrail/publications/hdr/Compstat_2000.pdf

Respondent Type	Percentage That Have Operational Wide-Area Visualization Tools	Value of Wide-Area Visualization Tools for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	23/44=52%	12/22=55%	10/22=45%
RC	14/16=88%	10/14=71%	4/14=29%
Others	9/28=32%	2/8=25%	6/8=75%

Table 2.2-14 — Usage and Value of Wide-Area Visualization Tools by Respondent Type

The survey also asked entities how they currently use their wide-area visualization tools for monitoring. Table 2.2-15 summarizes the responses.

What Types of Wide-Area Visualization Tools are Available in Your Application(s)?	Respondent Type		
	All	RC	Others
Frequency monitoring	18/22=82%	11/14=79%	7/8= 88%
Natural gas pipeline monitoring	1/22=5%	1/14=7%	0/8=0%
Inter-area phase angle separation monitoring	1/22=5%	0/14=0%	1/8=12%
Multi-area ACE monitoring	13/22=59%	11/14=79%	2/8=25%
Network topology island monitoring	8/22=36%	5/14=36%	3/8=38%
State estimator observable island monitoring	2/22=9%	2/14=14%	0/8=0%
High-speed phasor measurement monitoring	1/22=5%	1/14=7%	0/8=0%
System phase angle monitoring	2/22=9%	1/14=7%	1/8=12%
Voltage profile monitoring	14/22=64%	9/14=64%	5/8=63%
Multi-input artificial intelligence alarming and notification	1/22=5%	1/14=7%	0/8=0%

Table 2.2-15 — Wide-Area Visualization Tools — Current Implementation

The most prevalent uses for wide-area visualization tools are for frequency monitoring, multi-area ACE monitoring, and voltage profile monitoring. The Real-Time Tools Survey did not ask about details or methodology related to how the information is presented to operators. As noted in the Areas Requiring Further Analysis section below, RTBPTF recommends further research and analysis in the usage/implementation of wide-area visualization tools.

Selectable Data Trending

Selectable data trending is a type of visualization tool that can plot graphically selected power system values, using up-to-date data on the plot at a reasonable refresh rate. The majority of survey respondents (91 percent) report that they have selectable data trending and rate this type of visualization tool "essential"

(65 percent) or "desirable" (35 percent) for enhancing situational awareness. According to the survey, actual and/or historical/archived SCADA and application data are the most common types of data represented. Table 2.2-16 summarizes the survey results for selectable data trending by respondent type.

Respondent Type	Percentage That Have Operational Selectable Data Trending	Value of Selectable Data Trending for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	39/43=91%	18/36=50%	17/36=47%
RC	15/15=100%	8/15=53%	7/15=47%
Others	14/28=50%	10/21=48%	10/21=48%

Table 2.2-16 — Usage and Value of Selectable Data Trending, by Respondent Type

Reactive Reserve Monitor

A reactive reserve monitor uses static and dynamic sources to monitor reactive reserves in local geographic areas or major load centers. This tool can alarm the operator when a generating unit has reached its reactive capability or an area has approached the minimum reactive reserve requirement.[19] This type of tool could also function as the real-time user-interface representation of the documented procedures, practices, or guidelines for maintaining awareness of current and near-term reactive reserve capability (see Section 3.1, Reserve Monitoring). Only 35 percent of respondents report having a reactive reserve monitor tool available for their operators although 59 percent rate it "essential" for situational awareness (see Table 2.2-17).

[19] RTBPTF identifies the minimum reactive reserve requirement as an issue. See Section 3.1, Reserve Monitoring, for this discussion.

Respondent Type	Percentage That Have Operational Reactive Reserve Monitor	Value of Reactive Reserve Monitor for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	15/43=35%	7/13=54%	5/13=38%
RC	5/15=33%	3/5=60%	2/5=40%
Others	10/28=36%	4/8=50%	3/8=38%

Table 2.2-17 — Usage and Value of Reactive Reserve Monitor, by Respondent Type

Although use of this type of visualization tool is not prevalent, it is worth noting the survey results that identified some of the functional features of reactive reserve monitors, as shown in Table 2.2-18.

Functional Features of Reactive Reserve Monitors	Respondent Type		
	All	RC	Others
Available in study mode	3/14=21%	2/5=40%	1/9=11%
Available in real time	14/14=100%	5/5=100%	9/9=100%
Reserves are monitored area wide	9/14=64%	3/5=60%	6/9=67%
Reserves are monitored intra-area around load center	8/14=57%	4/5=80%	4/9=44%
Unit reactive limits are automatically adjusted based on reactive capability curves and MW output	9/14=64%	3/5=60%	6/9=67%
Unit reactive capability curves are adjusted in real time based on telemetry from the plant	5/14=36%	2/5=40%	3/9=33%
Static reactive capacity of shunt devices is automatically adjusted for real-time voltage	6/14=43%	3/5=60%	3/9=33%
Lagging reserves (total of unused capacitors, etc.) are calculated	9/14=64%	4/5=80%	5/9=56%
Leading reserves (total of unused reactors, etc.) are calculated	5/14=36%	3/5=60%	2/9=22%
Issues an alarm when an area/zone approaches its minimum reactive reserve	7/14=50%	4/5=80%	3/9=33%
Issues an alarm when a unit approaches its minimum/maximum reactive capability	4/14=29%	1/5=20%	3/9=33%
Voltage collapse calculations are part of this tool	2/14=14%	1/5=20%	1/9=11%
Area/Zone reactive demand includes load, loss, and charging Mvar for state estimator solutions	2/14=14%	2/5=40%	0/9=0%
Transmission-level capacitors and reactors are included in reserve calculations	9/14=64%	4/5=80%	5/9=56%
Low-voltage and customer-connected capacitors are included in reserve calculations	1/14=7%	1/5=20%	0/9=0%
Customer-connected motor load and distributed generation are included in reserve calculations	0/14=0%	0/5=0%	0/9=0%

Table 2.2-18 — Functional Features of Reactive Reserve Monitor

Remedial Action Scheme (RAS) Monitor[20]

A remedial action scheme (RAS) monitor provides tools/displays that allow operators to monitor the status of critical power system parameters, measure the proximity of these parameters to the triggering conditions for SPSs or total system failure, and alarms and advises operators regarding actions required to mitigate the pending power system condition. This tool is not in common use; only 38 percent of respondents indicate that they have this capability. However, in contrast to the whole population of respondents, 80 percent of RCs indicate that they have this type of tool available. Respondents that have an operational RAS monitor rate this tool as either "essential" (83 percent) or "desirable" (17 percent) for enhancing situational awareness (see Table 2.2-19).

Respondent Type	Percentage That Have Operational RAS Monitor	Value of RAS Monitor for Enhancing Situational Awareness	
		"Essential"	"Desirable"
All	16/42=38%	12/15=80%	3/15=20%
RC	12/15=80%	9/11=82%	2/11=18%
Others	4/27=15%	3/4=75%	1/4=25%

Table 2.2-19 — Usage and Value of RAS Monitor, by Respondent Type

RAS monitors are not prevalently used. However, it is worth noting the survey results regarding the functional features of this tool. Table 2.2-20 summarizes the survey results.

[20] The terminology was changed from the survey so as not to confuse it with "Remedial Action Scheme" as defined in the glossary section of the "Reliability Standards for the Bulk Electric Systems of North America" document.

Functional Features of RAS Monitor	Type of Respondent		
	All	RC	Others
Operators view the results of this application from SCADA/EMS displays	13/15=87%	9/11=82%	4/4=100%
Operators view the results of this application from other systems	4/15=27%	2/11=18%	2/4=50%
Operators can disable impending SPS based on determination that triggering conditions are false	3/15=20%	2/11=18%	1/4=25%
Alarms and results are based on real-time conditions	11/15=73%	7/11=64%	4/4=100%
Alarms and results are also based on contingency analysis	7/15=47%	6/11=55%	1/4=25%
Static, canned messages are used to inform the operator of recommended action	3/15=20%	2/11=18%	1/4=25%
Artificial Intelligence or multi-level heuristics are used to inform the operator of recommended actions	1/15=7%	1/11=9%	0/4=0%

Table 2.2-20 — Functional Features of RAS Monitor

Automatic Safety Net

An automatic safety net provides the tools/displays for operators to monitor, initiate, or disable triggering of schemes that shed firm load for under-voltage or under-frequency conditions. An automatic safety net could work with a RAS monitor. The automatic safety net is not a prevalent tool; only 37 percent of respondents indicate that they have this tool. Respondents that have operational automatic safety net visualization tools rate them as either "essential" (75 percent) or "desirable" (25 percent) for enhancing situational awareness (see Table 2.2-21).

Respondent Type	Percentage That Have an Operational Automatic Safety Net Visualization Tool	Value of Automatic Safety Net Visualization for Enhancing Situational Awareness	
		Essential	Desirable
All	16/43=37%	10/14=71%	4/14=29%
RC	4/15=27%	4/4=100%	0/4=0%
Others	8/28=29%	6/8=75%	2/8=25%

Table 2.2-21 — Usage and Value of Automatic Safety Net, by Respondent Type

Although the automatic safety net visualization tool is not prevalently used, it is worth noting the survey results regarding the functional features of this tool, which are summarized in Table 2.2-22.

Functional Features an Automatic Safety Net Visualization Tool	Respondent Type		
	All	RC	Others
Warning alarms are issued as conditions approach triggering (if time permits)	8/12=67%	2/4=50%	6/8=75%
Tripping points can be remotely disabled/enabled individually	6/12=50%	3/4=75%	3/8=38%
Tripping points can be remotely disabled/enabled in large groups	5/12=42%	3/4=75%	2/8=25%
Tripping points and/or boundaries are automatically changed as conditions merit	2/12=17%	1/4=25%	1/8=12%

Table 2.2-22 — Functional Features of Automatic Safety Net

Transaction Impact Monitor

A transaction impact monitor provides the tools/displays for operators to monitor scheduled transactions and interchange flows between BAs. The majority (72 percent) of survey respondents indicate that they have this type of tool. Respondents that have an operational transaction impact monitor rate this tool as either “essential” (82 percent), “desirable” (12 percent), or of “minimal” value (5 percent) for enhancing situational awareness. Current implementations of transaction impact monitors use real-time displays, updated for every schedule change. Table 2.2-23 summarizes the results of the survey for transaction impact monitors.

Respondent Type	Percentage That Have Operational Transaction Impact Monitor	Value of Transaction Impact Monitor for Enhancing Situational Awareness	
		“Essential”	“Desirable”
All	28/42=67%	20/27=74%	5/27=19%
RC	14/16=88%	11/14=79%	2/14=14%
Others	14/26=48%	9/13=69%	3/13=23%

Table 2.2-23 — Usage and Value of the Transaction Impact Monitor, by Respondent Type

Flowgate Monitor

A flowgate monitor provides the tools/displays for operators to monitor actual and contingency flows on designated flowgates. The NERC Glossary defines “flowgate” as “[a] designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.” This type of visualization tool provides flowgate information to operators; it could run either within or independent of SCADA/EMS systems. Fifty-nine percent of all respondents indicate that they have a flowgate monitor; eighty-one percent of RCs indicate that they have this feature available. Respondents that have an operational flowgate monitor rate this tool as either “essential” (88 percent) or “desirable” (13 percent) for enhancing situational awareness. As currently implemented across the industry, flowgate monitors display real-time data and generate alarms for predicted flowgate overloads. Table 2.2-24 summarizes the results of the survey for flowgate monitors.

Respondent Type	Percentage That Have an Operational Flowgate Monitor	Value of Flowgate Monitor for Enhancing Situational Awareness	
		“Essential”	“Desirable”
All	25/43=58%	21/24=88%	3/24=13%
RC	13/16=81%	12/13=92%	1/13=8%
Others	12/27=44%	9/11=82%	2/11=18

Table 2.2-24 — Usage and Value of Flowgate Monitor, by Respondent Type

Recommendations for New Reliability Standards

RTBPTF believes that operator ability to visualize the status of bulk electric system elements and parameters by means of visualization tools is an essential component of the monitoring process. The Real-Time Tools Survey reveals that entities have used slightly different methodologies and approaches to ensure that they have visualization tools that provide concise, visual monitoring and enhanced multiple views of relevant power system data in real time. Most entities have developed these tools based on their interpretations of operator needs as well as of the implementation of NERC standards.

RTBPTF interprets visualization tools as the user interface layer(s) for the tools/applications necessary to monitor and to maintain the reliability of the bulk electric system. In this report, RTBPTF recommends a mandatory minimum set of monitoring and analysis tools (the Reliability Toolbox; see the Reliability Toolbox Rationale and Recommendation section of this report):

- Alarm tools
- Telemetry data systems
- Network topology processor
- State estimator
- Contingency analysis

Each of these mandatory tools is discussed extensively in its respective sections of the report. Some of the visualization tools discussed in this report are used to present information from one or more of these recommended mandatory applications, which means that these visualization tools must be available. However, RTBPTF believes that it is not necessary for the NERC reliability standards to specify availability standards for these visualization tools in the same context as requiring the availability of the mandatory applications that these visualization tools support. The recommendations within this report focus on mandating the use and availability of the Reliability Toolbox instead of the availability of the user interface (i.e., the corresponding visualization tools.) Requiring the availability of the user interface for the applications is redundant and unnecessary.

Recommendation – S9

Establish a uniform formal process to determine the "wide-area view boundary" and show boundary data/results.

Recommendation – I2

Define wide-area view boundary.

Wide-Area View Boundary

The purpose statement of Standard IRO-003 states "[t]he Reliability Coordinator must have a wide area view of its own Reliability Coordinator Area and that of neighboring Reliability Coordinators." The NERC glossary defines "wide-area" as "[t]he entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits." RTBPTF interprets "wide-area view" as the monitoring boundary for reliability coordinators; it is the RC's view of the "wide area." Several RTBPTF recommendations depend on appropriate definition and exchange of information on bulk electric system elements, which in turn, for RCs, requires greater specificity in the definition of the "wide area." For more detail on the issues of wide-area view, see the Introduction Section.

RTBPTF Recommendation

RTBPTF recommends that NERC establish a uniform, formal process to determine the bounds of the "wide area" and the RC's "wide-area view." The *FERC Staff Assessment* states that "[t]he IRO standards do not specify the criteria for identifying critical facilities whose operating status can affect the reliability of neighboring systems and, therefore, hampers effective [w]ide [a]rea visualization."[21]

RTBPTF agrees with the *FERC Staff assessment* and, therefore, recommends that NERC establish a process to determine the critical flow and status information from adjacent reliability coordinator areas based on detailed system studies to allow the calculation of IROLs, to define what constitutes the bounds of the "wide area." This uniform, formal process would clarify the extent and detail required for the "wide area."

RTBPTF also introduces the concept of a "wide-area view boundary." RTBPTF defines "wide-area view boundary" as the network model boundary for the "wide area." For RCs, the "wide-area view boundary" defines the minimum required network model to support the monitoring requirements for the "wide area." This network model should contain all the bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) bounded by the wide-area view boundary. Sections 4.1, Model Characteristics, and 4.2, Modeling Practices and Tools, further discuss issues related to the "wide-area view boundary."

Once this formal definition process is established by NERC, RTBPTF recommends that a new requirement be established under the current Standard IRO-003 that mandates that each RC apply this formal process to identify its bounds for the its wide-area view. The following requirement is recommended:[22]

PR1. Each reliability coordinator shall identify the bounds of its wide area using the NERC-prescribed uniform formal process (Wide-Area Determination Process). Wide-area visualization tools shall show data/information that encompass the wide area.

RTBPTF recommends the following measure for requirement PR1:

PM1. The reliability coordinator shall demonstrate upon request that it is using the NERC-prescribed uniform formal process (Wide-Area Determination Process) to identify the bounds of its wide area as stated in Requirement PR1. Upon request, the reliability coordinator shall produce documentation describing the process and logs/documents demonstrating application of the process.

Rationale

RTBPTF believes that the wide-area view is analogous to the reliability monitoring boundary for RCs. Therefore, all of the tools and processes for the

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[21] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

[22] Proposed requirements are designated "PR," and proposed measures are designated "PM."

RC to monitor bulk electric system elements and parameters are bounded by the wide area. That is, tools like the state estimator and contingency analysis (and their corresponding power system network models) should be implemented to monitor the RC's wide area. Consequently, network models used by these tools shall cover at a minimum, the wide-area view boundary. A uniform, formal process (Wide-Area Determination Process) eliminates ambiguity for RCs regarding the method of determining the extent of the RC's monitoring boundary (the wide-area view).

Standard IRO-003 mandates that each RC monitor bulk electric system parameters that may have significant impacts upon its RC area and neighboring RC areas. Essentially, each RC is primarily responsible for bulk electric system parameters within its own RC area. However, Standard IRO-003 expands the monitoring requirement to neighboring RC areas based on the wide area.

In Section 1.1, Telemetry Data, RTBPTF recommends that each RC develop and maintain a list of specific bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) within its RC area (the Bulk Electric System Elements List). RTBPTF recommended that the Bulk Electric System Elements List contain the bulk electric system elements within the RC's area necessary for identifying potential or actual SOL or IROL violations within the RC area. Once each RC produces a Bulk Electric System Elements List, RTBPTF believes that this list could be the basis of the uniform, formal process being recommended in proposed requirement PR1 for determining the bounds of the wide area as well as the modeling characteristics for the wide-area view boundary.

If each RC has in its possession its own Bulk Electric System Elements list and is actively monitoring these elements within its own RC area, adjacent RCs could request access to a subset of the elements contained in each adjacent RC's Bulk Electric System Elements Lists. The requesting RC shall use the uniform, formal process to determine extent of the subset of the data it needs. This subset of bulk electric system elements from each adjacent RC's Bulk Electric System Elements List together with the RC's own Bulk Electric System Elements List would then define the bulk electric system elements and parameters for the RC's wide area. Figure 2.2-1 illustrates the concept of the "wide area" as the RC's monitoring boundary.

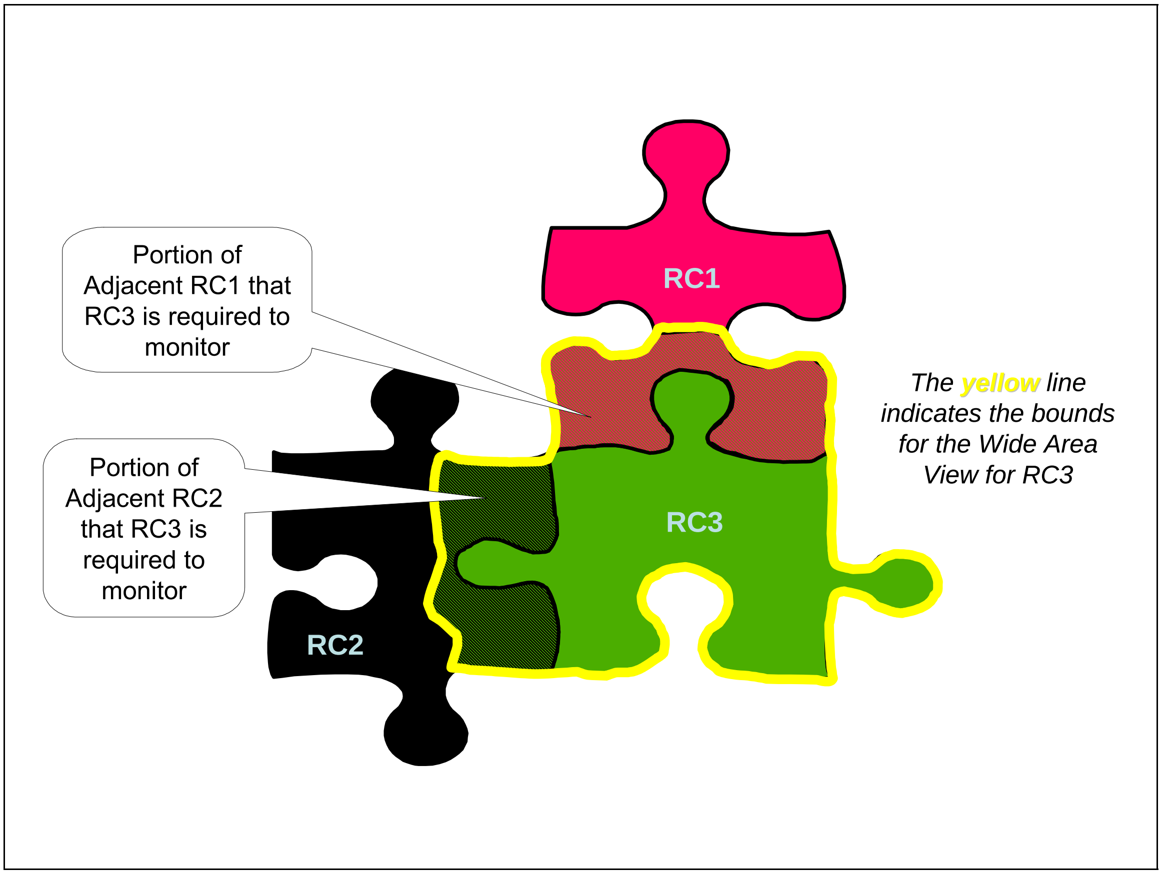

Figure 2.2-1 — Illustration of Wide-Area Concept Related to Monitoring Boundaries for RCs

Usage of Visualization Tools as Measures for Compliance

RTBPTF recommends adding/enhancing measures to require the usage of applicable visualization tools necessary for compliance with existing NERC reliability standards. RTBPTF believes that active demonstration of the usage of visualization tools should be used as measures of compliance with some existing standards. This emphasizes the use of visualization tools to aid reliability entities in "monitoring" bulk electric system elements and parameters.

The existing NERC reliability standards listed below require reliability entities to "monitor" bulk electric system elements and parameters. RTBPTF believes that the word "monitor" does not imply viewing large amounts of raw telemetered or application data. Reliability entities should use visualization tools to concisely organize information as a means to monitor bulk electric system elements and parameters. Visualization tools are highly dependent upon the host application's data (telemetry or application specific) that are provided to each type of visualization tool.

NERC Reliability Standard IRO-003, Reliability Coordination — Wide Area View

Standard IRO-003 states that the RC must have a wide-area view of its own RC area and that of neighboring RCs. Requirement R1 states, "[e]ach Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary, to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area." Requirement R2 states, "[e]ach Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives."

RTBPTF Recommendation

Standard IRO-003 requires a wide-area view for RCs, but it lacks specificity on the measures. RTBPTF recommends development of measures for the requirements specified by Standard IRO-003. The measures for compliance should include verification, through active demonstration, of the usage of visualization tools by operators to fulfill the requirements of the Standard IRO-003.

Once the bounds of the "wide area" are established, each RC shall be required to demonstrate the use of adequate visualization tools and/or summary displays (as appropriate) to comply with the "wide-area view" standard, as mandated by Standard IRO-003. Each RC shall demonstrate, at a minimum, the existence and usage of specific set of visualization tools and/or summary displays (as appropriate) corresponding for each requirement per Standard IRO-003 (see Table 2.2-25 below). As shown in Table 2.2-25, RTBPTF recommends a measure for each requirement in Standard IRO-003.

Standard IRO-003 Requirement[23]	Recommended Measures
R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	RTBPTF recommends that the following measure for Requirement R1.[24] PM1. Each reliability coordinator shall demonstrate the active use of visualization tools and summary displays listed below to comply with Requirement R1. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area. a. Contingency Analysis Summary Displays b. Dynamic Overview Displays or Dynamic Mapboard c. Wide-Area Visualization Tools Rationale: RTBPTF interprets the determination of "any potential System Operating Limit and Interconnection Reliability Operating Limit violations" as the output solution of the contingency analysis application. RTBPTF recommends contingency analysis as a mandatory tool for reliability coordinators. At a minimum, Requirement R1 requires the demonstration and usage of the contingency analysis application and its related summary displays and output solution. Section 2.6 of this report, Contingency Analysis, discusses the recommendations for the contingency analysis application. Requirement R1 also implies the demonstration and usage of the following list of visualization tools[25] and summary displays for bulk electric system elements within the reliability coordinator's wide area. a. Contingency Analysis Summary Displays b. Dynamic Overview Displays or Dynamic Mapboard c. Wide Area Visualization Tools The Real-Time Tools Survey indicates prevalent practice concerning dynamic overview displays (100%), dynamic mapboard (67%), and wide-area visualization tools (88%) among reliability coordinators. RTBPTF believes that mandating that RCs use wide-area visualization tools and either dynamic overview displays or a dynamic mapboard gives RCs the situational awareness capability mandated by Requirement R1. The scope of the use of these visualization tools is strongly noted by RTBPTF to encompass the RC's wide area. It is not sufficient just to show the RC area.

[23] Each requirement here is stated verbatim from the current Standard IRO-003.
[24] The numbering scheme for these proposed measures (PM) coincides with the existing requirements – e.g., the proposed measure for Requirement R1 is numbered PM1.
[25] The definitions of each type of visualization tool are discussed in the Summary of Findings section above.

Standard IRO-003 Requirement[23]	Recommended Measures
R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	RTBPTF recommends that the following measure for Requirement R2. PM2. Each reliability coordinator shall demonstrate the active use of contingency analysis summary displays to comply with Requirement R2. These summary displays shall show information within the reliability coordinator's wide area. <u>Rationale:</u> RTBPTF interprets the knowledge of "current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation" as the output solution of the contingency analysis application. At a minimum, this requires demonstration and usage of the contingency analysis application and its related displays and output solution. Section 2.6 of this report, Contingency Analysis, discusses the recommendations for the contingency analysis application. The second part of this requirement ("status of any facilities that may be required to assist area restoration objectives") is discussed in Section 3.7, Blackstart Capability, of this report.

Table 2.2-25 — Recommended Measures for Standard IRO-003

NERC Reliability Standard IRO-002, Reliability Coordination — Facilities

Standard IRO-002 states that RCs need information, tools, and other capabilities to perform their responsibilities. Requirement R7 of the standard requires that each RC have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.

Recommendation – S10

Develop compliance measures for verification of the usage of "wide-area overview display" visualization tools.

RTBPTF Recommendation

Standard IRO-002 is specific in requiring RCs to have "wide-area overview displays," but it lacks specificity regarding measures. RTBPTF recommends the development of a measure for the requirements specified in Standard IRO-002 (Requirement R7). The measure for compliance includes verification, through the active demonstration of the usage of visualization tools by the RC to fulfill the "wide-area overview display" requirement of the standard mentioned above. RTBPTF recommends the following measure for Requirement R7:[26]

[26] The numbering scheme for these proposed measures (PM) coincides with the existing requirements – e.g., the proposed measure for Requirement R7 is numbered PM7. Also,

PM7. Each reliability coordinator shall demonstrate the active use of visualization tools and summary displays listed below to comply with Requirement R7. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area.

a. Dynamic Overview Displays or Dynamic Mapboard
b. Wide Area Visualization Tools

Rationale

The rationale for this measure is the same as for Requirement R1 of Standard IRO-003. This recommended measure makes clear how to comply with the "wide-area view overview display" Requirement R7.

NERC Reliability Standard IRO-005 — Reliability Coordination — Current Day Operations

The standard's purpose states, "the Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas."

Requirement R1 states that each reliability coordinator shall monitor its reliability coordinator area parameters. The subrequirements are listed below verbatim from Standard IRO-005 (Requirement R1):

R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.
R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
R1.4. System real and reactive reserves (actual versus required).
R1.5. Capacity and energy adequacy conditions.
R1.6. Current ACE for all its Balancing Authorities.
R1.7. Current local or Transmission Loading Relief procedures in effect.
R1.8. Planned generation dispatches.
R1.9. Planned transmission or generation outages.
R1.10. Contingency events.

Requirement R7 is also discussed in other sections (for mandatory tools) with additional measures recommended by RTBPTF.

RTBPTF Recommendation

RTBPTF recommends that each RC demonstrate the use of adequate visualization tools and/or summary displays (as appropriate) to fulfill the monitoring requirements for each of the items listed in Requirement R1 of Standard IRO-005. Each RC shall demonstrate easily accessible visualization tools and/or summary displays (as appropriate) that show the appropriate information as specified by each sub-requirement under Requirement R1. Note that this is in addition to the measures recommended in Section 1.1, Telemetry Data.

RTBPTF recommends addition of measures based on demonstrated usage of visualization tools and/or summary displays (as appropriate) to provide clarity for reliability coordinators regarding how to comply with Standard IRO-005 (Requirement 1). As shown in Table 2.2-26, most of the sub-requirements give the reliability coordinator the flexibility of either demonstrating the active use of summary displays (as appropriate) based on data from other applications/tools or demonstrating the active use of the specified visualization tool(s) for a particular sub-requirement. Requirement R1.1 is the only sub-requirement that mandates that the RC demonstrate use of specific types of visualization tools. In most cases, summary displays are appropriate to fulfill the other sub-requirements (i.e., Requirement 1.2-Requirement 1.7 and Requirement 1.10).

Standard IRO-003, Requirement R1 Sub-requirements	Recommended Measures
R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.	RTBPTF recommends the following measure for Requirement R1.1:[27] PM1.1. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.1. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area. a. Dynamic Overview Displays or Dynamic Mapboard b. Wide-Area Visualization Tools c. Remedial Action Scheme Monitor or Automatic Safety Net <u>Rationale:</u> Note that recommended measures regarding the monitoring requirement for the "current status of Bulk Electric System elements" as mandated by Requirement R1.1 are also thoroughly discussed in Section 1.1, Telemetry Data. The Real-Time Tools Survey indicates that, among RCs, dynamic overview displays are widely used (100%), as are dynamic mapboard (67%), and wide-area visualization tools (88%). RTBPTF believes that mandating that RCs use wide-area visualization tools <u>and</u> either dynamic overview displays or dynamic mapboards will give RCs the situational awareness capability mandated by Requirement R1.1 to monitor "current status of Bulk Electric System elements." For example, a display containing the all the RC area generating units with their corresponding AVR status could demonstrate usage of wide-area visualization tools. RTBPTF also believes that Requirement R.1.1 mandates that RCs have situational awareness of the status of SPSs. RTBPTF interprets this mandate to mean that RCs must use either a RAS monitor or automatic safety net visualization tools. The Real-Time Tools Survey indicates that RAS monitors are commonly used (88%), and automatic safety nets are not (27%). RTBPTF believes demonstrated use of either of the two tools could be used to demonstrate active usage of visualization tools for situational awareness of RASs.

[27] The numbering scheme for these proposed measures (PM) coincides with the existing requirements – e.g., the proposed measure for Requirement R1.1 is numbered PM1.1.

<table>
<tr><th>Standard IRO-003, Requirement R1 Sub-requirements</th><th>Recommended Measures</th></tr>
<tr><td>R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.</td><td>RTBPTF recommends the following measure for Requirement R1.2:

PM1.2. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.2. Each of these visualization tools and summary displays shall show information within the reliability coordinator’s wide area.
a. State estimator solution summary displays or contingency analysis summary displays
b. Wide-area visualization tools containing the state estimator solution or the base-case solution of the contingency analysis application

<u>Rationale:</u>

RTBPTF interprets “current pre-contingency element conditions” as the state estimator solution or the base-case solution of the contingency analysis application. Section 2.5 of this report, State Estimator, discusses the recommendations for the state estimator application. Section 2.6 of this report, Contingency Analysis, discusses the recommendations for the contingency analysis application.

In addition, RTBPTF recommends that the RC be required to demonstrate the active use of wide-area visualization tools containing the state estimator solution or the base-case solution of the contingency analysis application. Wide-area visualization tools would aid RCs in focusing on important parameters/elements based on the state estimator solution or the base-case solution of the contingency analysis application.</td></tr>
<tr><td>R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.</td><td>RTBPTF recommends the following measure for Requirement R1.3:

PM1.3. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.3. Each of these visualization tools and summary displays shall show information within the reliability coordinator’s wide area.
a. Contingency analysis summary displays
b. Wide-area visualization tools containing output solution of the contingency analysis application

<u>Rationale:</u>

RTBPTF interprets “current post-contingency element conditions” as the output solution of the contingency analysis application. Section 2.6 of this report, Contingency Analysis, discusses the recommendations for the contingency analysis application.

In addition, RTBPTF recommends that the RC be required to demonstrate the active use of wide-area visualization tools containing the output solution of the contingency analysis application. Wide-area visualization tools would aid RCs in focusing on important parameters/elements based on the output solution of the contingency analysis application.</td></tr>
</table>

Standard IRO-003, Requirement R1 Sub-requirements	Recommended Measures
R1.4. System real and reactive reserves (actual versus required)	RTBPTF recommends the following measure for Requirement R1.4: PM1.4. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.4. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area. a. Wide-area visualization tools containing output of operating reserve calculations b. Reactive reserve monitor or wide-area visualization tools containing output of reactive reserve calculations <u>Rationale:</u> The "real reserves" are covered by the balancing resources and demand standards and termed "operating reserves." RTBPTF recommends that RCs be required to demonstrate the active use of wide-area visualization tools or summary displays (as appropriate) based on the output of operating reserve calculations in order to comply with the "monitoring" requirements of Requirement R1.4. Section 3.1, Reserve Monitoring, discusses recommendations for reserve monitoring. RTBPTF interprets "reactive reserves (actual versus required)" as the output of the reactive reserve monitor visualization tool for monitoring the status of reactive resources. This visualization tool monitors reactive resources (dynamic and/or static) to determine whether they are sufficient based on current conditions. It has the ability to alarm the operator when either a unit in the area has reached its reactive capability or there are insufficient reactive resources (dynamic and/or static) for an area. RTBPTF recommends that the RC be required to demonstrate the active use of the reactive reserve monitor visualization tool or an equivalent wide-area visualization tool or summary displays (as appropriate) based on the output of reactive reserve calculation as discussed in Section 3.1, Reserve Monitoring.

Standard IRO-003, Requirement R1 Sub-requirements	Recommended Measures
R1.5. Capacity and energy adequacy conditions	RTBPTF recommends the following measure for Requirement R1.5: PM1.5. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.5. Each of these visualization tools and summary displays shall show information within the reliability coordinator's wide area. a. Capacity assessment application summary displays or wide-area visualization tools containing output of the capacity assessment application. <u>Rationale:</u> RTBPTF interprets "capacity and energy adequacy conditions" as the output of the capacity assessment application. This application gives an overview of available generation capacity (MW or Mvar) in real-time. Section 2.12 of this report, Capacity Assessment, discusses recommendations for the capacity assessment application. RTBPTF recommends that RCs be required to demonstrate the active use of the capacity assessment application (with its corresponding summary displays) or an equivalent wide-area visualization tool that shows capacity and energy adequacy conditions.
R1.6. Current ACE for all Balancing Authorities	RTBPTF recommends the following measure for Requirement R1.6: a. Each reliability coordinator shall demonstrate the active use of the visualization tools or summary displays listed below to comply with Requirement R1.6. The visualization tools or summary displays shall contain the current ACE for all balancing authorities within the reliability coordinator area. <u>Rationale:</u> The current ACE for all of the RC's BAs is obtainable as ICCP-specific data. Compliance may be demonstrated by each RC showing the monitoring (through ICCP data exchange or direct telemetry methods) of the current ACE for all its BAs. Current ACE data are also required per Standard TOP-005. In addition, RTBPTF recommends that the RC be required to demonstrate the active usage of equivalent wide-area visualization tools or summary displays (as appropriate) that show ACE data of balancing authorities within the RC area.
R1.7. Current local or Transmission Loading Relief procedures in effect	RTBPTF is not recommending any measures requiring any visualization tool for Requirement R1.7. Section 2.14 of this report, Other Tools (Current and Operational), discusses the congestion management application, inter-regional real-time coordination for congestion management application, and inter-regional real-time coordination for market redispatch application.
R1.8. Planned generation dispatches	Not within the scope of RTBPTF
R1.9. Planned transmission or generation outages	Not within the scope of RTBPTF

Standard IRO-003, Requirement R1 Sub-requirements	Recommended Measures
R1.10. Contingency events	Requirement R1.1 addresses the continual monitoring of bulk electric system whereas Requirement R1.10 addresses event monitoring. When a critical facility (considered a contingent element) is unavailable, this may be a result of multiple bulk electric system elements indicating a change in status. For example, when a 230-kV transmission line is unavailable (a contingency event), this may be a result of transmission circuit breakers showing a status open. RTBPTF interprets the monitoring of "contingency events" as the output of alarm tools. RTBPTF is not recommending any measures related to visualization tools usage for Requirement R1.10. Section 2.1, Alarm Tools, discusses recommendations for alarm tools.

Table 2.2-26 — Recommended Measures for IRO-005, Requirement 1

NERC Reliability Standard TOP-006 — Monitoring System Conditions

Standard TOP-006 exists, "[t]o ensure critical reliability parameters are monitored in real-time." Requirement R2 states, "[e]ach Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources."

RTBPTF Recommendation

The requirement to use visualization tools is not limited to RCs but also applies to other reliability entities. In fact, the *Outage Task Force Final Blackout Report* attributes the lack of situational awareness by TOP FE's operators to the lack of an effective alternative to easily visualize the overall conditions once FE's alarm tools failed. An alternative means to readily visualizing overall system conditions, including the status of critical facilities, would have enabled FE operators to become aware of forced transmission-line outages in a timely manner even though the alarms were non-functional.

RTBPTF recommends the following measure for Standard TOP-006 (Requirement R2):[28]

PM2. Each reliability coordinator, transmission operator, and balancing authority shall demonstrate, at a minimum, the existence and usage of the following set of visualization tools and/or displays as a measure for compliance with Standard TOP-006 (Requirement 2):

a. Dynamic overview displays or dynamic mapboard
b. Reactive reserve monitor
c. Remedial action scheme monitor or automatic safety net

[28] The numbering scheme for these proposed measures (PM) coincides with the existing requirements – e.g., the proposed measure for Requirement R2 is numbered PM2.

Rationale

The rationale for Standard TOP-006, Requirement R2 is the same as for Standard IRO-003, Requirement R1 above. This is essentially the same requirement extended to TOPs and BAs.

Recommendation – G2

Consider human factors, ergonomics and maintenance/support issues in implementing visualization tools.

Recommendations for New Operating Guidelines

The implementation of different types of visualization tools would most likely be a customized effort by each entity, so a general operating guideline for each type of visualization tool would be of little or no value. Therefore, RTBPTF is not recommending any operating guidelines specifying which type of visualization tools to use/implement. However, numerous existing research studies/reports in the area of visualization and user interface could be used by entities in designing and implementing their visualization tools. Issues to consider in implementing visualization tools include, but are not limited to, the following:

- Human factors, ergonomics
- Industry adoption of standardized or common presentation of data
- Technical innovations in visualization tools
- Maintenance/support issues

Features of Wide-Area Visualization Tools

In the area of wide-area visualization tools, the Real-Time Tools Survey provides insight regarding desired features of certain industry implementations. These features are worthy of consideration by entities implementing wide-area visualization tools. Functional features to consider in implementing wide-area visualization tools include, but are not limited to, the following:

- Capability to render information using conventional graphing techniques (e.g., pie charts, flashing lines, etc), as well as rendering information using more advanced techniques (e.g., contouring of voltage data, reliability hotspots, etc.)
- Capability to link wide-area visualization tools to alarm tools.
- Capability to mix data from different sources (e.g., telemetry system data with state estimator solution data)
- Capability to present electric system data either geographically or through a schematic representation

- Capability to automatically create a visual representation of the entity's network model; i.e., the wide-area visualization tool is driven by the network model.

Recommendation – A4

Conduct research to assess current technology and practices related to the use and application of visualization tools

Areas Requiring Further Analysis

RTBPTF recommends that NERC, with the help of other research (or government) entities, continue to assess current technology and practices related to the use and application of visualization tools. RTBPTF also notes that Recommendation 13 of the *Outage Task Force Final Blackout Report* states, "DOE should expand its research programs on reliability-related tools and technologies. More investment in research is needed to improve grid reliability, with particular attention to improving the capabilities and tools for system monitoring and management." Items to be included in this research related to visualization tools are:

- Development of practical real-time applications for wide-area system monitoring using phasor measurements and other synchronized measuring devices, including post-disturbance applications
- Development and use of enhanced techniques for modeling and simulation of contingencies, blackouts, and other grid-related disturbances
- Development of practical human factors guidelines for power system control centers

To reiterate, the *Outage Task Force Final Blackout Report* listed the following recommendations from previous investigations concerning visualization tools[29]:

- In the control center, use a dynamic line loading and outage display board to provide operating personnel with rapid and comprehensive information about the facilities available and the operating condition of each facility in service.
- Give control centers the capability to display to system operators computer-generated alternative actions specific to the immediate situation, together with expected results of each action.

[29] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 108.

Recommendation – A5

Establish a Visualization Tools Working Group (VTWG) to foster and facilitate sharing of best practices.

RTBPTF also recommends the following for NERC's consideration:

- Establish a Visualization Tools Working Group (VTWG) to foster and facilitate sharing of best practices within the industry for the use of visualization tools. This working group could continue to recommend and develop standards and operating guidelines in the area of best methods and practices in presenting information to operators.
- Establish industry and technical forums that involve academic, research organizations, and other organizations to aid and guide the industry in the area of visualization tools.

Examples of Excellence

With visualization tools, the following entities have taken slightly different approaches to ensure that they have user interfaces that provide concise, visual monitoring and enhanced multiple views of relevant power system data in real time. These visualization tools are available to operators to help them monitor and better understand system events and/or conditions across power systems that may be affecting reliable operation in their part of the power system. Visualization tools are provided to the operators to maintain or enhance their situational awareness.

RTBPTF cites the implementation of the facilitated transaction checkout (FTC) tool by all balancing authorities within the Northeast Power Coordinating Council as an example of excellence (See EOE-4 in Appendix E). FTC is a message structure that enables neighboring reliability entities to query each other's interchange transaction stack and perform an automated comparison prior to performing verbal checkout, thus improving the accuracy associated with transaction checkout.

RTBPTF cites the implementation of PowerWorld Retriever by Southwest Power Pool to provide a system overview (i.e., voltage contouring), as well as alarms using pie charts and flashing lines, as an example of excellence (See EOE-5 in Appendix E).

RTBPTF cites the implementation of an expansive wide-area overview display with underlying BA and one-line displays, including flowgate and reactive monitoring displays, by MISO as an example of excellence (See EOE-6 in Appendix E).

RTBPTF cites American Transmission Company's use of an application that interfaces directly with its EMS to provide system operators with a dynamic wide-area overview of its network topology as well as state estimation of the neighboring systems as an example of excellence (See EOE-7 in Appendix E).

Section 2.3
Network Topology Processor

Definition

The network topology processor (NTP) is a SCADA-based application that determines facility status and station configuration based on breaker and switch status data. The processor converts a nodal network model into a bus-branch model, for use by other applications such as the state estimator. It may perform the same function for study network applications such as power flow.

Background

Software tools such as the network NTP, state estimator, and contingency analysis allow RCs and TOPs to maintain current information about the condition of their bulk electric system facilities and to monitor the impacts on those facilities of events in neighboring systems.

The electricity system behaves quite dynamically during the course of a day. NTP tracks changes in system configuration using algorithms that regularly analyze phenomena such as changing breaker and switch status. The result is an accurate model of the current system configuration and preparation of data needed for other situational awareness tools. NTP configuration models are vital to downstream applications such as state estimators.

RTBPTF agrees with a recommendation made at the July, 2004 FERC Technical Conference[30] that NTP use be a minimum requirement for reliability entities. The task force also fully supports the *Outage Task Force Final Blackout Report* observation that the state estimator require a "… model of the power system that reflects the configuration of the network (i.e. which facilities are in service and which facilities are not)..."[31] This conclusion effectively mandates NTP usage.

The constant evaluation of electrical connectivity is essential to provide input to the state estimator (and other near-real-time network applications). Consequently, the NTP must be highly available and its analyses highly accurate for reliability entities to effectively monitor bulk electric system conditions. As a result of the blackout investigation findings, NERC issued directives to FE, MISO, and Pennsylvania-New Jersey-Maryland Interconnection (PJM), including a mandate that FE ensure that its state estimator and contingency analysis functions "execute reliably full contingency analyses automatically every ten

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[30] Macedo, Frank. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14.

[31] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 47.

minutes or on demand, etc." NERC also required MISO to fully implement and test its NTP to provide operating personnel a real-time view of system status for "all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems." Entities were also required "to establish a means of exchanging outage information" within their footprints and with neighboring systems to ensure that each state estimator "has accurate and timely information to perform as designed."[32]

The purpose of the NTP section of the Real-Time Tools Survey was to obtain a snapshot of current NTP usage throughout the industry. Special emphasis was placed on determining reliability entities' practices for viewing and monitoring bulk electric system elements as well as maintenance and support practices related to NTP. Results summarized below emphasize responses from RCs and TOPs because limited response was received from BAs.

See Section 2.4, Topology and Analog Error Detection, for a discussion of enhanced topology error detection.

Summary of Findings

Key survey results from the NTP section are that NTPs are operational at many RCs and TOPs, required to develop topology models for the state estimator and contingency analysis applications, used to independently detect isolated and/or disconnected equipment, used to support other situational awareness tools (i.e., dynamic mapboards), executed frequently and quickly, and monitored to ensure high availability.

RTBPTF recommends additions to/modifications of certain NERC reliability standards to ensure NTP availability, performance, and accuracy. The task force recommends that compliance measures be appropriately coordinated with the alarm tools and/or state estimator applications.

Survey results suggest that NTP is commonly used throughout the industry, primarily by system operators and control room personnel. The survey found that NTP algorithms execute rapidly and on a regular or frequent basis.

Considering these findings and the necessity for developing accurate connectivity models reflecting real-time system conditions, the task force classifies NTP as a critical real-time tool.[33]

A significant number of RCs and TOPs responded to the survey questions regarding NTP, and responses from these two groups were fairly consistent.

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[32] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 152.
[33] The concept of a "critical real-time tool" is explained in Section 5.4, Critical Applications Monitoring.

Other groups responded in statistically insignificant numbers; therefore, most of the discussion in this section is limited to RC and TOP responses.

Characteristics of Network Topology Processors

The survey results confirm that NTPs are widely used and operational throughout the industry, as shown in Table 2.3-1. Ninety-four percent of RCs (16 out of 17) and 67 percent of TOPs (18 out of 27) who responded to the survey report that they have NTPs. In addition, almost all RCs (16 out of 16) and TOPs (17 out of 18) that have this application indicate that it is operational. Two TOPs plan to add NTPs in the future, and 1 RC and 7 TOPs do not plan to add NTPs.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, "32/38=84%" means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

NTP Characteristics	All	RCs
Do you have Network Topology Processor?	35/47=74%	16/17=94%
Is your NTP operational?	34/35=97%	16/16=100%
Is your NTP Off-the-Shelf with some Customization?	11/34=32%	7/16=44%
Is your NTP Off-the-Shelf?	17/34=50%	6/16=38%
Is your NTP Supplied By SCADA/EMS Vendor?	30/34=88%	14/16=88%
Is your NTP Fully Integrated With Production SCADA/EMS?	32/34=94%	14/16=88%

Table 2.3-1 — NTP Characteristics

Users overwhelmingly employ "off-the-shelf" or "off-the-shelf with some customization" NTP packages (81 percent of RCs, 13 out of 16, and 88 percent of TOPs, 15 out of 17), which suggests that vendor packages with satisfactory NTP functionality are available. NTP packages are typically fully integrated with users' EMS systems. However, some respondents use third-party or in-house products. One RC's NTP is interfaced to the SCADA/EMS, and another RC's NTP is a stand-alone product. Nearly 90 percent of RCs' (14 out of 16) and TOPs' (15 out of 17) NTPs were provided by their SCADA/EMS vendors. Two RCs and no TOPs obtained their NTPs from a third-party vendor. Two TOPs and no RCs developed their NTPs in house.

Respondents with functioning NTP applications report overwhelmingly [94 percent of RCs (15 out of 16) and 94 percent of TOPs (15 out of 16)] that their NTPs use a topology algorithm rather than a Boolean or other type of approach. Most of the 33 RCs and TOPs responding to the NTP questions report that their NTPs are interfaced for use by the state estimator and power-flow applications. High percentages (about two-thirds or more) of both RCs and TOPs interface their NTPs to SCADA and contingency analysis applications. Other functions are also interfaced but to a lesser degree. See Table 2.3-2. Several entities took the time to comment that their NTPs are also interfaced to an outage-scheduling system, which suggests that this interface, not specifically itemized in the survey question, may be relatively common as well.

NTP Application Interfaces	All	RCs
SCADA	26/34=76%	11/16=69%
Alarm Tools	14/34=41%	8/16=50%
Monitoring and Visualization Tools	16/34=47%	10/16=63%
Topology Error Detection	15/34=44%	10/16=63%
State Estimator	32/34=94%	16/16=100%
Contingency Analysis	26/34=76%	14/16=88%
Critical Facility Loading Assessment	4/34=12%	2/16=13%
Power Flow	29/34=85%	14/16=88%
Study Real-Time Maintenance	10/34=29%	6/16=38%
Other(s)	3/34=9%	2/16=13%

Table 2.3-2 — NTP Application Interfaces

Seventy-nine percent of respondents (12 RCs and 14 TOPs) report that they need to manually update non-telemetered internal facility status points. This suggests that even though a majority of respondents interface their SCADA systems with the NTP, many must manually maintain status information in some locations to support all equipment in their models. At least two-thirds of RCs (12 out of 16) and TOPs (11 out of 17) indicate that they must perform manual updates of external facility status points. If these status points are not kept current, their "wide-area view"[34] of the bulk power system could be affected.

NTP Users

The majority of respondents, i.e., 94 percent of RCs (15 out of 16) and 82 percent of TOPs (14 out of 17), indicate that operators and other control room staff are the primary users of NTP, suggesting that the application is primarily a situational awareness tool for operators. Although others use it, the percentages are much smaller, as Table 2.3-3 shows.

[34] "Wide-area view" is a term introduced by Standard IRO-003.

Users	Who are primary Users?		Who are secondary Users?	
	All	RCs	All	RCs
System Operators and/or Other Control Room Staff	30/34=88%	15/16=94%	3/29=10%	1/15=7%
Operations Support Staff	16/34=47%	8/16=50%	13/29=45%	7/15=47%
EMS and/or information technology (IT) Support Staff	9/34=26%	4/16=25%	16/29=55%	7/15=47%
Supervisory and/or Management Staff	5/34=15%	1/16=6%	8/29=28%	3/15=20%
Other(s)	0/34=0%	0/16=0%	4/29=14%	3/15=20%
Not Used On a Continuous Basis (7 x 24 x 365)	0/34=0%	0/16=0%	1/29=3%	0/15=0%

Table 2.3-3 — Who uses NTP?

Features and Functions

All 33 RCs and TOPs rank NTP as "essential" or "desirable," which makes clear the importance of this application. The survey responses shown in Table 2.3-4, as well as the respondents' comments cited at the end of this paragraph, illustrate the variety of roles that this application plays.

NTP Functions and Features	All	RCs
Identify electrical islands & equipment in each island	31/34=91%	15/16=94%
Island detection is Essential	15/29=52%	8/14=57%
Island detection is Desirable	13/29=45%	5/14=36%
Identify equipment that is open-ended at one terminal	29/32=91%	14/15=93%
Open-ended equipment detection is Essential	14/27=52%	8/12=67%
Open-ended equipment detection is Desirable	12/27=44%	4/12=33%
Identify equipment that is completely de-energized	27/31=87%	12/14=86%
De-energized equipment detection is Essential	12/26=46%	7/12=58%
De-energized equipment detection is Desirable	12/26=46%	4/12=33%
Individually override any status in NTP, including taps	27/31=87%	13/14=93%
Override of individual status points is Essential	23/27=85%	12/13=92%
Override of individual status points is Desirable	4/27=15%	1/13=8%
Override a large number of statuses from saved case	8/31=26%	6/14=43%
Override of status pts. from saved case is Essential	3/5=60%	3/5=60%
Override of status pts. from saved case is Desirable	2/5=40%	2/5=40%
Detect and identify abnormal split buses	13/30=43%	6/14=43%
Abnormal split bus detection is Essential	6/13=46%	3/6=50%
Abnormal split bus detection is Desirable	7/13=54%	3/6=50%
Detect & identify abnormal breaker & switch statuses	25/30=83%	10/14=71%
Abnormal breaker/switch status detection is Essential	13/20=65%	3/ 7=43%
Abnormal breaker/switch status detection is Desirable	6/20=30%	4/ 7=57%
Define different voltage limits at each node	13/30=43%	8/14=57%
Different voltage limits at each node is Essential	8/12=67%	4/ 7=57%
Different voltage limits at each node is Desirable	4/12=33%	3/ 7=43%
Chronologically view all facility outages & returns	16/30=53%	9/14=64%
Chronological view of outages/returns is Essential	13/15=87%	9/9=100%
Chronological view of outages/returns is Desirable	2/15=13%	0/9=0%

Table 2.3-4 — NTP Functions and Features

NTP's roles include: preparing models for the state estimator/contingency analysis, identifying equipment outages, identifying de-energized equipment, identifying the existence of multiple network islands, and driving dynamic mapboards.[35] The number of respondents that have the features discussed in this paragraph suggests that these features are common and readily available.

[35] See Section 2.2, Visualization Tools, for a discussion of the application and prevalence of dynamic mapboards.

Most respondents [94 percent of RCs (15 out of 16) and 88 percent of TOPs (15 out of 17)] indicate that their NTPs can detect two or more electrical islands, and 93 percent of RCs (13 out of 14) and all TOPs (14 out of 14) rank this feature as "essential" or "desirable." About one-half of RCs (8 out of 14) and TOPs (6 out of 14) can specify the minimum number of buses in a valid electrical island. Respondents can identify up to a minimum of 10 electrical islands; the maximum number of islands that can be identified is essentially unbounded (9,999). One RC and 2 TOPs that do not have the island detection function indicate that it would be "desirable." Detection of open-ended or de-energized equipment is also a common feature. Very high percentages of respondents [93 percent of RCs (14 out of 15) and 88 percent of TOPs (14 out of 16)] report that their NTP applications can detect open-ended equipment at one terminal, and 86 percent of RCs (12 out of 14) and 88 percent of TOPs (14 out of 16) can detect de-energized equipment. Users overwhelmingly (more than 90 percent) rate these features as "essential" or "desirable."

The respondent's comments below suggest the importance and variety of NTP implementations:

> "There is topology processing that is integrated into the State Estimator and the other network applications. We also have a SCADA topology processor that runs as part of the SCADA environment to indicate de-energized equipment based solely on SCADA information."
>
> "Topology outputs are used for mapboard indication and line, transformer, and outage alarming."
>
> "Provides bus/branch model for State Estimator and other network applications. Provides current and chronological history of facility status. Detects network islanding."
>
> "Local and wide area situation awareness would be very difficult to achieve, if at all, without network topology. One could not, generally speaking, achieve good contingency analysis results without NTP."

Additional survey questions reveal other, less common uses of NTP. For example, 43 percent of RCs (6 out of 14) and 40 percent of TOPs (6 out of 15) use NTP to detect abnormal split buses. All of the RCs (6 out of 6) and TOPs (6 out of 6) that have abnormal split bus detection rank this feature "desirable" or "essential," with RCs rating the function as essential more frequently than TOPs. Seventy-one percent of RCs (10 out of 14) and 93 percent of TOPs (14 out of 15) can also detect abnormal breaker and switch status. However, this feature is not used by all who have it. Most RCs (7 out of 7) and TOPs (11 out of 12) that have and use this feature consider it "essential" or "desirable." In contrast to many other NTP-related features and functions, TOPs (9 out of 12) rank this feature "essential" more often than did RCs (3 out of 7), suggesting that TOPs that have the feature consider it to be important. It should be noted that every one of the RCs (4 out of 4) that reported that they did not have the feature indicate that it would be “desirable.”

Performance, Monitoring, and Availability

Several survey questions attempted to quantify NTP performance, which could be useful information for establishing norms. The results indicate that the NTP function requires minimal execution time and is generally set to run automatically and fairly frequently. When asked how their NTP is normally triggered to run in real time, all RCs (16 out of 16) and all TOPs (17 out of 17) report that their NTPs were triggered to run automatically.

Users report a fairly wide range of cycle times - from a low of two seconds to a high of 1,800 seconds - with an average of just under 300 seconds (five minutes). For most, the function executes rapidly. The 16 RCs and 17 TOPs report times averaging well under 10 seconds, and many respondents (11 out of 16 RCs and 12 out of 17 TOPs) report times of five seconds or less. Seven RCs and TOPs require as little as one second to execute the application, and no one reports an execution time that exceeds 30 seconds.

In addition to addressing execution speed and frequency, the survey addressed availability and monitoring. This information is of interest to the task force for establishing reasonable recommendations for standards and compliance measures. Companies were asked to report multiple monitoring tools if applicable. Eighty percent of RCs (8 out of 10) and 80 percent of TOPs (8 out of 10) report that the most common method of monitoring NTP availability is a “watchdog.” Other techniques include 1 RC using a redundant system comparison and 5 RCs and TOPs using alarm displays, flag and system messages, operator monitoring, and system health checks to ensure availability. Of those reporting, 7 out of 10 RCs and 6 out of 10 TOPs indicate that alarm tools show NTP status to support personnel; 50 percent of RCs (5 out of10) use continuous displays for this purpose. Paging systems, web-based or special application displays, and email and phone calls are also employed but by less than 50 percent of any reporting group. Two-thirds of the RCs and TOPs responding (12 out of 18) indicate that failed status is detected and reported within 300 seconds or less. Responses from 10 RCs and 8 TOPs indicate that failed status is detected and reported in time frames ranging from a minimum of one second to a maximum of 1,560 seconds (26 minutes).

Frequency of Regular Manual Health Checks for the Entity's NTP	All	RCs
Weekly	1/21=5%	0/12=0%
Daily	4/21=19%	3/12=25%
Hourly	1/21=5%	1/12=8%
As Needed	12/21=57%	5/12=42%
Other(s)	3/21=14%	3/12=25%

Table 2.3-5 — NTP Manual Health Checks

Table 2.3-5 summarizes the responses regarding how often a regular manual NTP health check is performed. Twenty-one respondents answered this survey question. Overall, 42 percent (5 out of 12) of RCs and 57 percent (12 out of 21) TOPs that responded to this survey question report that regular, manual health checks are performed on an as-needed basis to ensure that the NTP application is running successfully. The remaining respondents report that their NTP health checks are performed continuously with different periodicities as indicated in the table.

NTP Monitor and Metrics	All	RCs
Does your NTP have the ability to detect and independently notify operators and support staff that the NTP is down or functioning incorrectly?	20/30=67%	10/14=71%
Do you use a Watchdog to detect NTP failures?	16/20=80%	8/10=80%
Is the status of NTP monitored continuously (24x7x365)?	21/21=100%	12/12=100%
Do operators attempt to resolve problems prior to notifying support?	8/21=38%	5/12=42%
Are your support personnel available continuously (24x7x365)?	18/21=86%	11/12=92%
Do you have historical NTP solution rate data and/or metrics?	8/31=26%	6/15=40%

Table 2.3-6 — NTP Monitor and Metrics

Overall, only 26 percent of respondents (6 out of 15 RCs and 2 out of 15 TOPs) have solution availability metrics to describe how often NTP solves for a given number of runs (see Table 2.3-6). Although this is a statistically small group, 100 percent of those that have metrics (6 out of 6 RCs and 2 out of 2 TOPs) use them, and most (5 out of 6 RCs and 2 out of 2 TOPs) rate them "desirable" or "essential" for situational awareness. Sixty percent of respondents without metrics (including 7 out of 9 RCs and 7 of 13 TOPs) indicate that metrics would have minimal value. Two-thirds of RCs (4 out of 6) and half of the TOPs (1 out of 2) with metrics generate their statistics automatically. No respondents generate them manually. However, 1 respondent's metrics are based on the number of solutions obtained while another respondent runs scripts each day to derive the metrics.

See the "Support" subsection below for further discussion.

Questions regarding the periodicity of metrics and the period of unavailability that respondents consider will have significant impact on their system operations elicited only a small number of responses (6 total). Therefore, RTBPTF can draw no conclusions on these issues. It is of interest that availability statistics appear to be based on estimated rather than calculated values. In addition, although only a limited number of respondents address the leading causes of NTP unavailability, the two causes cited are bad telemetry (with good quality codes) and data link/lost telemetry (at least 1 respondent reports that more than 50 percent of problems resulted from these two causes).

Enhanced Functionality

Of those responding to questions about NTP enhanced functionality, most RCs (13 out of 14) and TOPs (13 out of 16) can override individual status telemetry, including tap positions. All respondents that have this feature rate it “essential” or “desirable” (13 out of 13 RCs and 13 out of 13 TOPs). Some RCs (6 out of 14) and TOPs (2 out of 16) can also override status telemetry, in bulk, from saved cases. This feature, which is useful in the event of an ICCP (or similar) data-link loss, appears to be more highly valued by RCs than TOPs; all 5 RCs but none of the TOPs rank this feature “essential” or “desirable.”

Fifty-seven percent of RC respondents (8 out of 14) and 27 percent of TOPs (4 out of 15) can define different voltage limits at each node and use the most restrictive limit for each resultant bus. Although 100 percent of those using this feature (7 out of 7 RCs and 4 out of 4 TOPs) consider it “essential” or “desirable,” fewer than one-third of the RCs and TOPs who do not have this feature rank it “desirable” (5 out of 17). There may be some confusion about the purpose and/or application of nodal voltage limits given the importance placed on them by those who use this feature in contrast to those who do not (and do not believe they need it).

Sixty-four percent of RCs respondents (9 out of 14) and 40 percent of TOPs (6 out of 15) can view chronologically all facility outages and returns. Almost all RCs (9 out of 9) and TOPs (5 out of 6) that have this feature use it. Of those using it, RCs unanimously (9 out of 9) rank it “essential,” and all TOPs (5 out of 5) rank it “essential” or “desirable.” Of those that do not have the feature, 80 percent of RCs (4 out of 5) and 55 percent of TOPs (5 out of 9) indicate that the feature would be “desirable.”

Support

The essential nature of network topology processing is evidenced by the number of respondents that have tools to monitor the status of this function and alert support staff to problems. As previously noted (Table 2.3-6), of those responding, 71 percent of RCs (10 out of 14) and 67 percent of TOPs (10 out of

15) can detect and independently notify operators and support staff that the NTP is down or functioning incorrectly. All 10 RCs and 10 TOPs with this feature consider it "essential" or "desirable," and 50 percent of RCs (2 out of 4) and 100 percent of TOPs (5 out of 5) that do not have the feature state that it would be "desirable."

A variety of support groups may get involved when NTP problems arise. The "System Operators and/or Other Control Room Staff" group is most commonly notified when NTP fails; 80 percent (8 of 10) of RCs and 60 percent of TOPs (6 of 10) notify this group. Operations support staff are often notified when NTP fails at RCs (7 of 10) but not at TOPs (only 1 of 10). The responses were more balanced for notification of EMS and/or information technology (IT) Support Staff; 5 of 10 RCs and 6 of 10 TOPs report using this strategy. Smaller numbers of respondents notify supervisory personnel or "Others." One company stated that "24/7 and on-site support staff are paged." See Table 2.3-7.

What Personnel are Notified of NTP Failures?	All	RCs
System Operators and/or Other Control Room Staff	14/20=70%	8/10=80%
Operations Support Staff	8/20=40%	7/10=70%
EMS and/or IT Support Staff	11/20=55%	5/10=50%
Supervisory and/or Management Staff	2/20=10%	2/10=20%
Other(s)	1/20=5%	1/10=10%

Table 2.3-7 — What Personnel are Notified of NTP Failures?

About 70 percent of those responding, including 80 percent of RCs (12 out of 15) and 57 percent of TOPs (8 out of 14), have tools to monitor NTP status and alert support personnel to problems. See Table 2.3-7. All RCs (12 out of 12) and TOPs (8 out of 8) that have this feature consider it "essential" or "desirable." Of those that do not have NTP Status Monitoring and Support Personnel Notification, 2 out of 3 RCs and 3 out of 6 TOPs rate this feature "desirable." All respondents that have the feature (12 RCs and 8 TOPs) monitor NTP support status 24x7x365. Roughly 40 percent of RCs (5 out of 12) and 38 percent of TOPs (3 out of 8) indicate that operators attempt to resolve problems prior to notifying support staff. Of those using NTP monitors, 92 percent of RCs (11 out of 12) and 75 percent of TOPs (6 out of 8) have support staff available continuously (24x7x365).

The survey responses indicate that support personnel notification procedures are well established and formalized, which suggests the importance respondents place on maintaining NTP's operational status. RCs and TOPs rely on multiple notification methods. Overall, two-thirds of those reporting, including 83 percent of RCs (10 out of 12) and 50 percent of TOPs (4 out of 8), indicate that the most common notification method is that operators process alarms and call support personnel as needed. The next-most-common method, used by about 50 percent overall, is to have support personnel on call, ready to connect remotely after business hours to fix problems as necessary [50 percent of RCs (6 out of 12), and 63 percent of TOPS (5 out of 8)]. Approximately 43 percent overall, with 42 percent of RCs (5 out of 12) and 50 percent of TOPs (4 out of 8) have support personnel on call who can report on site after business hours to fix reported problems. About one-third overall, including 4 out of 12 RCs and 3 out of 8 TOPs, rely on automatic paging systems activated by the application to notify support personnel of problems. Overall 33 percent, including 42 percent of RCs (5 out of 12) and 13 percent of TOPs (1 out of 8), have support staff on duty, monitoring applications continuously. One company resolves problems the next business day.

The majority of RCs and TOPs have de-bugging tools. See Table 2.3-8. Overall, program error logs and displays (13 out of 17) and program source codes (12 out of 17) are the most commonly used de-bugging tools. Embedded parameters/flags and code debugging software are used to a lesser extent. All RCs (11 out of 11) and 50 percent of TOPs (3 out of 6) with de-bugging tools rank them “desirable” or “essential,” and 100 percent of RCs (4 out of 4) and 75 percent of TOPs (6 out of 8) that have no de-bugging tools indicate that these tools would be “Desirable.” This suggests that improved de-bugging tools would be useful for NTP support. The tools currently available vary. Respondents who report having this feature tend to have multiple de-bugging tools.

What Types of De-Bugging Tools do You Have?	All	RCs
Do you have debugging tools for NTP?	18/31=58%	11/15=73%
Embedded debug parameters/flags that could be enabled/disabled	7/17=41%	5/11=45%
Program Error Logs and Displays	13/17=76%	8/11=73%
Program Source Code	12/17=71%	7/11=64%
Code Debugging Software	7/17=41%	5/11=45%
Other(s)	2/17=12%	2/11=18%

Table 2.3-8 — Types of De-Bugging Tools

In response to questions about NTP support activities, all respondents indicated that they assign in-house staff to NTP support (12 out of 12 RCs and 8 out of 8 TOPs); a few respondents involve vendors in support activities (3 out of 12 RCs and 0 out of 8 TOPs). For almost 40 percent of all respondents, including 42 percent of RCs (5 out of 12) and 20 percent of TOPs (1 out of 5), operators and support personnel use written procedures to fix NTP problems; about 67 percent of the RCs (8 out of 12) and 40 percent of TOPs (2 out of 5) use vendor documentation for this purpose. Some respondents state that customized displays, on-the-job experience, and specialized training are required for personnel to be proficient at diagnosing problems and de-bugging the application. Some respondents also perform regular manual NTP health checks using a combination of written procedures (6 out of 10 RCs and 0 out of 6 TOPs) and vendor documentation (2 out of 10 RCs and 3 out of 6 TOPs). In some cases, customized on-line displays assist with failure detection and de-bugging;

one company performs health checks when they notice discrepancies between map board and SCADA systems. No one uses interactive help guides for these purposes. See Section 2.4, Topology and Analog Error Detection, for a discussion of survey results regarding software tools that address metering/status inconsistencies, etc.

Recommendations for New Reliability Standards

RTBPTF considers NTP a mandatory tool for ensuring bulk electric system situational awareness. RTBPTF believes that NTP is of equal importance to the other mandatory tools such as the state estimator and contingency analysis, especially when used to drive alarming and visualization tools. Accordingly, RTBPTF recommends modifications to existing standards to clarify that use of NTP is mandatory (see the Reliability Toolbox Rationale and Recommendation section). In the following discussions, RTBPTF supports the major recommendation to make NTP mandatory.

The results of the RTBPTF survey detailed above support the assertion of Macedo (2004)[36] that a NTP is a minimum requirement — i.e., an essential tool for operators. NTP availability and recommendations are discussed in detail in the following subsections below.

Recommendation – S1

Mandate the following reliability tools as mandatory monitoring and analysis tools

- Alarm Tools
- Telemetry Data Systems
- Network Topology Processor
- State Estimator
- Contingency Analysis

Network Topology Processor: Mandatory Monitoring and Analysis Tool

Survey results indicate that NTPs are delivered as a standard part of commercially available, modern SCADA/EMS systems. Existing NERC reliability standards require the use of "adequate analysis tools" to aid operators in maintaining situational awareness for the bulk electricity system. Standard IRO-002 (Requirement R7) states "[e]ach Reliability Coordinator shall have ***adequate analysis tools*** [emphasis added] such as state estimation, pre and post-contingency analysis capabilities (thermal, stability, and voltage), and wide area overview displays." Specifying the NTP as part of the Reliability Toolbox[37] eliminates the vagueness in the current NERC reliability standards regarding

[36] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

[37] The Introduction to this report discusses the inclusion of the Network Topology Processor as part of the Reliability Toolbox.

whether NTP, as defined, is mandatory. The recommendation also provides clarity to the term “adequate analysis tools.”

Recommendation – S8

Specify and measure minimum availability for network topology processor

Network Topology Processor Availability

The two main uses of the NTP are:

- To develop electric connectivity models as input to the state estimator, contingency analysis, or other analysis tools
- To generate operator displays for alarming and visualization (i.e., mapboards) of the status of elements of the bulk electric system (i.e., whether they are energized, open ended, or de-energized) as well as when electrical islands exist

For the first type of use, if an entity is using NTP only as an input to the state estimator, contingency analysis, or other analysis tools, the availability requirements for the state estimator[38] and contingency analysis[39] are sufficient to ensure that the entity’s NTP is available. That is, if the entity’s state estimator and contingency analysis are compliant per their respective availability standards, having a separate availability metric for NTP availability is unnecessary and redundant.

For the second type of use, RTBPTF recommends that reliability entities monitor the performance of their NTPs and measure availability because, for this use, the operators depend on NTP for situational awareness.

RTBPTF Recommendation

RTBPTF recommends that all RCs and TOPs be required to monitor the performance of their NTPs and measure availability when NTPs are used to generate operator displays for alarming and visualization (i.e., dynamic mapboards) of the status of elements of the bulk electric system (i.e., whether they are energized, open ended, or de-energized) as well as when electrical islands exist. RTBPTF believes that when NTP is used in this fashion, it needs to run more often and to be available.

[38] The availability requirement for state estimator is discussed in detail Section 2.5.
[39] The availability requirement for contingency analysis is discussed in detail Section 2.6.

This recommendation shall only apply to entities that have stand-alone NTPs (i.e., a totally separate application that develops the electric connectivity models)[40] that drive alarm tools and visualization tools. RTBPTF recommends that a new requirement be established under the current Standard TOP-006 (Monitoring System Conditions) that shall apply to both RCs and TOPs and require NTP availability:

> PR1. Network Topology Processor (NTP) Availability. Each Reliability Coordinator and Transmission Operator shall operate its NTP such that its NTP shall have at least one test topology change (or "watchdog" event) generated and processed at least every Telemetry Data System scan rate. This test event (or "watchdog" event) could originate from a test field device or could be application generated.

Although the NERC Standards process might address other factors in considering this recommendation, RTBPTF recommends the following measure for the requirement stated above:

> PM2. Each Reliability Coordinator and Transmission Operator shall maintain NTP application logs, reports, or documents demonstrating that the Responsible Entity's NTP processed the test topology change (or "watchdog" event) according to Requirement PR1.

Rationale

The electricity system behaves quite dynamically during the course of a day. NTP could be used to track changes in system configuration using algorithms that regularly analyze phenomena such as changing breaker and switch status in real time. The result is an accurate model of the current system configuration and preparation of data needed for other situational awareness tools. Used in this fashion, an available and robust NTP is essential to operators for timely detection of network topology changes. A metric to measure NTP availability provides a standardized method to measure performance.

Current Network Topology Determination

Standard IRO-005 (Requirement R1.1) states that each reliability coordinator shall monitor its reliability coordinator area parameters, including "[c]urrent status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection

[40] Some entities have a state estimator that has integrated the NTP functions and is not used for the purpose of alarming and visualization. Only stand-alone NTPs that drive alarm and visualization tools would have a required availability metric.

Systems) and system loading." RTBPTF recommends that Standard IRO-005 (Requirement R1.1) be modified to include a requirement that status information associated with transmission and generation elements be processed to determine current network topology. As a measure, topology results should be displayed to operators through alarms and visualization tools to indicate when equipment is disconnected, de-energized, or electrically isolated.

RTBPTF Recommendation

Standard IRO -005 (Requirement R1.1) should be modified as follows:

R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading. In addition, status information associated with transmission and generation Bulk Electric System and wide-area network elements shall be processed to determine current network topology. Results of the topology analysis shall be used to make operators aware of electrical islands and disconnected or de-energized equipment immediately after they are detected.

RTBPTF recommends the following measures for the modified requirement stated above:

PM1.1. Demonstrate that status change(s) are processed by NTP (or equivalent application[41]) to provide accurate configuration data before and after the change(s). Demonstrate that de-energized or disconnected equipment and formation of electrical islands are immediately displayed to operators via visualization tools.

Rationale

The task force survey results and comments make clear that NTP is an important, commonly used operator tool. NTP's primary functions include analyzing and establishing network topology and detecting electrical islands and disconnected or de-energized equipment. The *Outage Task Force Final Blackout Report* implies NTP's critical nature and importance for dynamically determining connectivity.

Several survey respondents' comments reinforce the importance of NTP. One respondent states that "local and wide area situation awareness would be very difficult to achieve, if at all, without network topology.

[41] Entities may used their Telemetry Data Systems (e.g., SCADA topology processing through Boolean logic equations/definitions) to provide topology detection functionality.

The task force recognizes that NTP functionality is multi-dimensional and that NTP is required to maintain the reliability of the bulk electric system. Topology analysis enhances operator situational awareness. Several survey respondents use NTP output independently of the network connectivity/topology to drive dynamic mapboards or other display devices that can serve as “outage display boards,” as the sample quotes below indicate:

> “There is topology processing that is integrated into the State Estimator and the other network applications. We also have a SCADA topology processor that runs as part of the SCADA environment to indicate de-energized equipment based solely on SCADA information.”
>
> “Topology outputs are used for mapboard indication and line, transformer outage alarming.”

These activities directly support recommendations in Section 7 of the *Outage Task Force Final Blackout Report,* which compares the August 14, 2003 blackout with previous disturbances. In the discussion of System Visibility Procedures and Operator Tools, the report cites the following recommendation (among others) from previous investigations:

> In the control center, use a dynamic line loading and outage display board to provide operating personnel with rapid and comprehensive information about the facilities available and the operating condition of each facility in service.[42]

The task force agrees and recommends that standards be modified to support activities that drive outage display boards or other devices and tools and provide operating personnel with ”rapid and comprehensive information about the facilities available.”

Applicability Statement for Recommended Standards

RTBPTF recommends that all RCs and TOPs be required to have NTP for monitoring the status of bulk electric system equipment to analyze electrical connectivity in near real time and prepare electrical models for further analysis by the state estimator, contingency analysis, etc. as defined in the recommended additions or modifications to the NERC Standards applicable to RCs and TOPs. Other responsible entities that use network topology processors to support or complement their RCs’ ability to operate the bulk electric system reliably in accordance with formal agreements, contracts, or established practices or procedures shall be subject to the same standards for NTPs as their RCs.

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[42] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p.108.

Recommendation – G3

Develop a chronological outage/return summary in network topology processor for recreating events and aiding state estimator.

Recommendations for New Operating Guidelines

In Section 2.9, Study Real-Time Maintenance, RTBPTF recommends the development of operating guidelines for study real-time maintenance applications. This capability is useful for maintaining highly available, accurate network analysis tools and supports the *Outage Task Force Final Blackout Report* Recommendation 37: "Improve IT forensic and diagnostic capabilities." The applications cited by RTBPTF as important to "improve IT forensic and diagnostic capabilities" should include NTP. About 50 percent (16 out of 30) of all survey respondents can view, chronologically, all facility outages and returns. Of the respondents that do not have this feature, 64 percent (9 out of 14) reported that it would be "desirable." RCs favored this feature more strongly than TOPs (100 percent of RCs rated it "essential.") A chronological outage/return summary is useful for recreating events and aiding state estimator troubleshooting. RTBPTF recommends that an Operating Guideline be developed for this NTP function.

Areas Requiring More Analysis

RTBPTF did not identify any Areas Requiring More Analysis related to NTP.

Examples of Excellence

The RTBPTF did not identify any Examples of Excellence related to NTP.

Section 2.4
Topology and Analog Error Detection

Definition

Topology and analog error detection (TAED) utilizes a computer application to identify and/or automatically override incorrect SCADA information regarding the statuses of breakers and switches. TAED is used to support NTP and improve the accuracy and robustness of the state estimator application. TAED also may identify and/or automatically ignore analog SCADA measurements that are unreasonable or inconsistent with network connectivity. Topology and analog error detection can serve as a pre-processor to other applications and can debug problems in the solutions those other applications produce. TAED can evaluate data, removing inconsistencies that may occur, for example, when direct information on equipment status indicates an open circuit while analog data suggests that power is flowing.

Background

This section of the report was developed to assess applications designed to eliminate or override incorrect or unreasonable status and/or analog data before NTP and the state estimator are executed. This pre-processing could enhance NTP and improve the quality of SE solutions.

TAED tools have great potential as pre-processors and debuggers for improving the performance of state estimator and other real-time tools. Although the industry would benefit from their universal use, their use currently is limited, perhaps because they are less effective than they need to be. TAED tools require redundant measurements in order to evaluate situations, identify inconsistent data, and provide accurate results. Developers of these tools should be encouraged to work with users to determine the model accuracy and measurement redundancy needed for the tools to perform well.

Because TAED is not used widely, RTBPTF does not consider this a critical reliability tool for operators and thus does not recommend creating or modifying reliability standards or operating guidelines to include TAED. RTBPTF does, however, recommend that TAED be analyzed further because this tool has potential to enhance NTPs and improve the quality of state estimator solutions.

Summary of Findings

Although TAED tools are available, the small number of survey responses makes it difficult to draw conclusions about industry-wide trends.

Survey responses and comments suggest that TAED tools are not generally used successfully, at least in part because there may be insufficient redundancy in the measurements available for analysis.

One respondent notes that "Topology Error Detection is used with our State Estimator. It has not proven very useful at this time. It works fairly well in well-measured parts of the system, but these were easy to detect before."

Section 2.3, Network Topology Processor, discusses in detail topics such as developing bus-branch models and detecting open equipment. In addition, some aspects of TAED are almost universally integrated into state estimator processes, as described in Section 2.5, State Estimator.

Prevalence and Perceived Value

Overall, 45 percent of those who responded to the TAED section of the Real-Time Tools Survey (21 out of 47) report having applications that provide TAED. This compares with 74 percent of respondents who reported having NTPs. RCs tend to use TAED more than do TOPs. Sixty-five percent of RCs (11 out of 17) report having operational TAED applications whereas just 27 percent of TOPs (7 out of 26) have operational TAED applications (1 TOP reports having a non-operational application). Two RCs and 4 TOPs indicate that they plan to acquire TAED.

The 9 respondents who submitted written comments on TAED convey a range of opinions about the application, as illustrated by the following quotations.

> "This feature allows RC1 to be aware of the telemetry which is not accurate. This improves situational awareness in monitoring the electrical power grid."
>
> "We've experienced some occurrences and it is useful but the occurrences are rare."
>
> "Topology Error Detection is used with our State Estimator. It has not proven very useful at this time. It works fairly well in well measured parts of the system, but these errors were easy to detect before."
>
> "Very essential."
>
> "On our system this is part of the state estimator preprocessing. It is not a stand alone application. Analogs and statuses that are inconsistent are identified in the application logs."
>
> "We don't have Topology Error Detection."
>
> "The use of a topology and analog error detection algorithm is one of the most important tools of our advance tools. It provides us the information to correct any measurement and false switch states. We can then send the right topology to our state estimator."

"Debugging solution problems without analog error detection would be very difficult, if not impossible in a r/t time line."

"Topology error detection is a separate function from analog error detection. Only analog error detection is functional at this time."

Availability and Interface with Other Applications

Survey results suggest that users can easily purchase TAED applications. Ten out of 11 RCs and all 7 TOPs that have operational applications report that their TAED software is "off-the-shelf" or "off-the-shelf with some customization." No one reports using applications that are highly customized or developed in house. As might be expected, the RCs and TOPs that have software supplied by their EMS vendors note that it is fully integrated with SCADA/EMS. Of 2 RCs who report having third-party products, one indicates that the package is fully interfaced with EMS, and the other reports using a stand-alone TAED.

Table 2.4-1 illustrates the various applications that respondents report are interfaced with TAED.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, "32/38=84%" means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

TAED Interfaces	All	Reliability Coordinators
SCADA	11/20 = 55%	4/11 = 36%
Alarm tools	6/20 = 30%	2/11 = 18%
Monitoring and visualization techniques	7/20 = 35%	6/11 = 55%
Network topology processor	11/20 = 55%	7/11 = 64%
State estimator	19/20 = 95%	11/11 = 100%
Contingency analysis	7/20 = 35%	5/11 = 45%
Critical facility loading assessment	0/20 = 0%	0/11 = 0%
Power flow	8/20 = 40%	6/11 = 55%
Study real-time maintenance	5/20 = 25%	4/11 = 36%
Other(s)	1/20 = 5%	1/11 = 9%

Table 2.4-1 — TAED Interfaces

Users

System operators and other control room staff are the primary users of TAED applications, as reported by 73 percent of RCs (8 out of 11) and 71 percent of TOPs (5 out of 7). As shown in Table 2.4-2, operations support staff and EMS and/or IT support staff are variously identified as primary or secondary users. Supervisory and management staff are very infrequently identified as users.

Users	Who are Primary Users?		Who are Secondary Users?	
	All	RCs	All	RCs
System operators and/or other control room staff	13/20 = 65%	8/11 = 73%	4/18 = 22%	2/11 = 18%
Operations support staff	9/20 = 45%	7/11 = 64%	10/18 = 56%	7/11 = 64%
EMS and/or IT support staff	10/20 = 50%	4/11 = 36%	6/18 = 33%	2/11 = 18%
Supervisory and/or management staff	0/20 = 0%	0/11 = 0%	3/18 = 17%	1/11 = 9%
Other(s)	0/20 = 0%	0/11 = 0%	2/18 = 11%	2/11 = 18%

Table 2.4-2 — Users of TAED

Features and Functions

Of those responding, 82 percent of RCs (9 out of 11) and 67 percent of TOPs (4 out of 6) state that their TAED uses a topology-based algorithm. No respondents report that their TAED uses a Boolean logic approach; 32 percent of all RCs and TOPs (5 out of 17) report "other" approaches. One respondent comments that "Analog Error Detection is part of their [state estimator] SE solution," and others comment that they use a "vendor custom algorithm" or "State Estimator error processing."

Eight out of 12 RCs and all 7 TOPs indicate that their applications can detect incorrect statuses of breakers and switches. The perceived value of this feature is unclear, given that 4 RCs and 4 TOPs report it would be "desirable" to have, and 5 RCs who use the feature rate it "essential" or "desirable." In contrast, 3 out of the 8 RCs who have the feature don't use it, and 1 TOP indicates it has only minimal value. These responses may indicate that although the concept is good, current implementations are ineffective, that the "payback" does not justify use of the feature, or that the feature simply is not used widely.

Overall, 75 percent of respondents (6 out of 8) report that their TAED application detects inconsistent analog and status measurements. Sixty percent of RCs (3 out of 5) and 100 percent of TOPs (3 out of 3) note that they define bad status as occurring when the analog measurement (flow) is inconsistent with the status measurement. Sixty percent of RCs (3 out of 5) and zero TOPs report that they also define bad status as occurring when status is unavailable but surrounding measurements are available. Only 4 respondents report having and using the capability to automatically override bad status, suggesting that this feature currently has limited perceived value.

All respondents (all 12 RCs and 7 TOPs) report that their TAED applications are capable of detecting unreasonable and inconsistent analog SCADA values based on topology. The survey provided two examples of this ability: 1) detecting a zero-voltage measurement at an energized bus, or 2) detecting and identifying analog values that are inconsistent with each other, such as when the sum of power flows at a bus is not close to zero. Almost all RCs (11 out of 12) and all 7 TOPs who have this feature report that it is operational. Those who use the feature consider it "essential" or "desirable." Table 2.4-3 summarizes the reasonableness/consistency checks that TAED applications provide.

Reasonableness/Consistency Checks	All	RCs
Voltage out of limits	15/20 = 75%	9/11 = 82%
Large flow on open-ended or de-energized branches	12/20 = 60%	6/11 = 55%
Sum of power flows at a bus is near zero	9/20 = 45%	4/11 = 36%
Taps outside of range	8/20 = 40%	4/11 = 36%
Unit output outside of limits	8/20 = 40%	5/11 = 45%
Flow exceeds rating	8/20 = 40%	5/11 = 45%
Small flow on In-Service branches	5/20 = 25%	3/11 = 27%
Sign of loads	5/20 = 25%	2/11 = 18%
Large losses on branch	4/20 = 20%	1/11 = 9%
Flow has same sign on both ends of branch	3/20 = 15%	2/11 = 18%
Received flow is greater than sent flow on branch	3/20 = 15%	1/11 = 9%
Other(s)	2/20 = 10%	1/11 = 9%

Table 2.4-3 — Reasonableness/Consistency Checks

The only checks that at least 50 percent of all RCs and TOPs use are voltage out of limit and large flow on open-ended or de-energized branches.

Of the 12 RCs whose applications can ignore unreasonable analog data in the state estimator solution based on topology, 9 report having this feature operational. Of the 7 TOPs who have this capability, 6 report that it is operational. All 9 RCs and 6 TOPs who use the capability deem it "essential" or "desirable."

Overall, 80 percent of respondents report that their TAED systems execute periodically, including 9 out of 11 RCs (62 percent) and 6 out of 7 TOPs (85 percent). Five out of 11 RCs (45 percent) and 5 out of 7 TOPs (71 percent) report executing the application manually or based on SCADA events (change of status or rate-of-change). Only 3 RCs report executing the program in response to disturbance events. Fifty percent of RCs (4 out of 8) indicate they execute TAED after a manual override of data (as does 1 TOP) and after an invalid/suspect solution (as do 2 TOPs). Other triggers, such as those based on a schedule or other mechanism, are used less frequently. Several respondents comment that the application can be executed at the discretion of staff or in response to predefined breakers and analog rates of change.

Based on responses from 9 RCs, the application executes periodically at intervals that range from 60 seconds to 30 minutes, with 8 out of 9 RCs reporting periodic execution every 5 minutes or less. TOPs estimate intervals that range from 10 seconds to 15 minutes, with 5 TOPs indicating that periodic execution occurs every 5 minutes or less. Nine RCs report speeds of execution that range from 1 to 30 seconds, with 7 of the 9 reporting speeds of 10 seconds or less. Seven TOPs report speeds of execution that range from 1 second to 3 minutes, with 4 indicating that the application runs in 10 seconds or less.

Monitoring, Availability, and Support

The survey asked about the availability of users' TAED applications, including how software problems/failures are detected and what typical responses are to problems. Only 4 RCs and 4 TOPs indicate that they can automatically detect and independently notify operators and support staff that TAED is unavailable or functioning incorrectly, so no conclusions can be drawn about industry trends in automated detection and notification. Five RCs who don't have this capability, however, say it would be "desirable," and 100 percent of those who have the capability call it "essential."

Only 5 RCs and 3 TOPS responded to the remaining survey questions concerning the monitoring and reporting of the status of TAED applications. Overall, 80 percent of these respondents, including 4 RCs and 2 TOPs, report that TAED status is monitored continuously (24 hours per day, 365 days per year). Two RCs and 2 TOPs report that operators initially attempt to resolve problems although 60 percent of the time operators are not first responders. When problems occur, most frequently system operators and/or other control room staff are notified; however, 4 RCs report that EMS or IT support staff are notified, 2 RCs indicate that operations support staff are notified. All of those reporting indicate that support staff respond to problems within 15 minutes of being notified.

Only 4 RCs and 3 TOPs responded to questions about who maintains and supports the TAED application. All those responding indicate that in-house staff maintain and support TAED. One RC indicates that vendor staff also are involved in supporting the application.

Just 3 RCs and 1 TOP report having historical metrics to record how often the TAED application solves for a given number of runs, but all respondents consider the feature "essential" or "desirable." Two respondents indicate that statistics are measured automatically. (The survey defined TAED solutions as 100 percent available if, for every periodic execution within a given time period, TAED solves.) Three RCs and 4 TOPs who don't have these metrics consider them "desirable." Responses to survey questions about the mean time of TAED unavailability, acceptable duration of unavailability, and frequency and acceptable rates of failure were not statistically relevant (only 2 RCs and 1 TOP responded).

Few responses were received to questions about documentation and procedures. Overall, 56 percent (including 2 out of 4 RCs and 2 out of 3 TOPs) report using vendor documentation to guide operators and support personnel in fixing TAED problems. Only 3 RCs and no TOPs report using written procedures. A few comment that experienced staff members are needed to respond to problems and that those in support will "do what is needed."

Nearly 75 percent of responding RCs (8 out of 11) indicate they have tools to aid in debugging their TAED application whereas only 43 percent of the TOPs (3 out of 7) report having those tools. Only 6 RCs use the tools, but all 3 TOPs use them. All RCs (6) and TOPs (3) using the tools consider them "essential" or "desirable" and, overall, 6 out of 8 respondents who do not have debugging tools consider such tools "desirable."

Based on limited survey responses, debugging tools are most often available through program error logs and displays (5 out of 6 RCs and 2 out of 3 TOPs) although sometimes they are part of the program source code (3 out of 6 RCs and 2 out of 3 TOPs). Embedded debugging parameters/flags also can produce debugging output, according to 2 out of 6 RCs and 2 out of 3 TOPs. In addition, 3 out of 6 RCs and 1 out of 3 TOPs report having code debugging software. One respondent notes that they have "software that downloads EMS data and runs comparisons to identify analog errors."

Recommendations for New Reliability Standards

RTBPTF does not recommend any new reliability standards or modifications to existing standards related to TAED.

Areas Requiring More Analysis

The task force recommends that providers of TAED tools consult with their customers who use (or try to use) these tools to identify and address barriers to successful implementation. These tools have great potential for improving the performance of the state estimator and other critical real-time tools, and the industry would benefit from their wider use.

Examples of Excellence

The RTBPTF did not identify any Examples of Excellence related to TAED.

Section 2.5
State Estimator

Definition

A state estimator is an application that performs statistical analysis using a set of imperfect, redundant, telemetered power-system data to determine the system's current condition. The system condition or state is a function of several variables: bus voltages, relative phase angles, and tap changing transformer positions. A state estimator can typically identify bad analog telemetry, estimate non-telemetered flows and voltages, and determine actual voltage and thermal violations in observable areas. The state estimator application has two main uses. It provides:

1. a base case for reliability-analysis applications
2. input to other system monitoring tools

The state estimator solution is typically used as the base case for other reliability-related applications, such as contingency analysis. In some cases, the state estimator is used primarily as the basis for information communicated to operators regarding power system status; e.g., the state estimator drives the alarm application that alerts operators to power system events.

Background

The state estimator application has two main uses. It provides:

1. a base case for reliability-analysis applications
2. input to other system monitoring tools

RCs and TOPs must have current information about the status of their bulk electric system facilities (system visibility) and must also be aware of events and changes in facility status in neighboring systems (situational awareness). System visibility and situational awareness depend on software tools such as the state estimator and contingency analysis. The subsections below address the use of the state estimator to maintain situational awareness. Other sections of this report address other situational awareness tools, including contingency analysis.

State estimator algorithms filter telemetry data to resolve inherent errors in the meters used to record the data. State estimators use real-time measurements from telemetry data systems to formulate a complex mathematical model of the power system that reflects the network configuration. The state estimator then uses real-time system data to estimate the voltage and phase angle at each bus, which in turn are used to estimate real and reactive power flow through each line and transformer. With sufficient metering redundancy, state estimator results are theoretically more accurate than measurements themselves. The state estimator's equipment voltage and loading information is used by reliability analysis tools, such as contingency and power-flow analysis, to simulate various conditions and outages so that operators can evaluate bulk electric system reliability. In some cases, the state estimator solution (rather than telemetry data systems) is the primary monitoring information and interface to alarm tools.

State estimation is typically performed for areas within each RC's footprint (the "RC area") as well as areas just beyond the boundaries of the RC area to include facilities within the RC's "wide area." Section 2.2 of this report, Visualization Techniques, discusses the issues related to the monitoring of the "wide area," which is key to each RC's awareness of the interconnected grid. Sections 4.1, Model Characteristics, and 4.2, Modeling Practices and Tools, discuss modeling issues related to the wide-area view boundary.

For TOPs, who are not also RCs, the state estimator scope is typically local and focuses on the TOP's internal area of responsibility. Wide-area view is not required of TOPs; however, their local view must extend beyond their internal footprint to some degree because of the modeling required for them to perform robust contingency analyses.

The state estimator is one of the first major reliability analysis applications that processes data from telemetry data systems (i.e., systems that process SCADA and ICCP data) and provides operators with a solution showing the current state of the power system. If the state estimator fails, the reliability analysis applications that depend on it (e.g., contingency analysis, power flow) cannot run; in other words, system visibility is lost, and the operator cannot detect potential SOL or IROL violations. This problem is more profound if the state estimator is the operator's primary monitoring tool.

The state estimator section of the Real-Time Tools Survey attempts to obtain a snapshot of current state estimator availability and usage in the industry. The survey emphasizes reliability entities' (RCs', TOPs', BAs') current use of the state estimator for viewing/monitoring bulk electric system elements. The survey also addresses state estimator maintenance and support practices. Because state estimators are highly dependent on network models, this section of the report also highlights issues related to modeling and practices, particularly the external network model. RTBPTF classifies the state estimator as a critical real-time tool[43] and recommends additions and modifications to certain NERC reliability standards to ensure state estimator availability and solution quality.

The *Outage Task Force Final Blackout Report* describes state estimator use as follows:

[43] The concept of a critical real-time tool is explained in Section 5.4, Critical Applications Monitoring.

> Transmission system operators must have visibility (condition information) over their own transmission facilities, and recognize the impact on their own systems of events and facilities in neighboring systems. To accomplish this, system state estimators use the real-time data measurements available on a subset of those facilities in a complex mathematical model of the power system that reflects the configuration of the network (which facilities are in service and which are not) and real-time system condition data to estimate voltage at each bus, and to estimate real and reactive power flow quantities on each line or through each transformer. Reliability coordinators and control areas that have them commonly run a state estimator on regular intervals or only as the need arises (i.e., upon demand). Not all control areas use state estimators.[44]

The state estimator must be available, and its solution must be accurate for reliability entities to effectively monitor bulk electric system conditions. In analyzing the causes of the 2003 blackout, the *Outage Task Force Final Blackout Report* states,

> One of MISO's primary system condition evaluation tools, its state estimator, was unable to assess system conditions for most of the period between 12:15 and 15:34 EDT [August 14, 2003], due to a combination of human error and the effect of the loss of the Dayton Power and Light Stuart-Atlanta line on other MISO lines as reflected in the state estimator's calculations. Without an effective state estimator, MISO was unable to perform contingency analyses of generation and line losses within its reliability zone. Therefore, MISO could not determine that with Eastlake 5 down, other transmission lines would overload if FE lost a major transmission line, and could not issue appropriate warnings and operational instructions.[45]

NERC played an important role in the blackout investigation, and, as a result of the investigation findings, issued directives on February 10, 2004 to FE, MISO, and PJM to complete remedial actions by June 30, 2004 correcting deficiencies identified as factors contributing to the blackout. These directives focused on the state estimator and related applications. NERC required FE to ensure that its state estimator and contingency analysis functions "execute reliably full contingency analyses automatically every ten minutes or on demand," and are

[44] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 47.
[45] Ibid, p. 46.

used to notify operators of potential first contingency violations.[46] NERC also required that MISO fully implement and test its network topology processor to provide operating personnel a real-time view of system status for "all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems." MISO also had "to establish a means of exchanging outage information with its members and adjacent systems such that the MISO state estimator has accurate and timely information to perform as designed." NERC further required that MISO fully implement and test its state estimator and contingency analysis tools "to ensure they can operate reliably no less than every ten minutes."[47]

These NERC directives indicate the importance of the state estimator for maintaining system reliability.

Summary of Findings

The responses to the state estimator section of the RTBPTF survey reveal varying degrees of practice and implementation related to the state estimator application. The subsections below address survey findings regarding: usage of state estimators**,** applications that depend on state estimator solutions, features of state estimators, timing and length of state estimator runs, convergence rate and availability of state estimators, accuracy of state estimator solutions, monitoring of external facilities, presentation of state estimator results, and maintenance and troubleshooting of state estimators.

State Estimator Usage & Prevalence

A large percentage of survey respondents use state estimators. Seventy-five percent (36 out of 48) of respondents, including all RC respondents (17 out of 17), have a state estimator (Table 2.5-1). Ninety-seven percent (35 out of 36) of the respondents that have a state estimator, including all of the RCs (17 out of 17), say that it is operational (Table 2.5-2).

Do You Have State Estimator?	RC	Other	Total
Yes	17	19	36
No		12	12
All	**17**	**31**	**48**

Table 2.5-1 — Respondents that have a State Estimator

46 U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p.152.

47 Ibid, Page 152.

Is Your State Estimator Operational?	RC	Other	Total
Yes	17	18	35
No		1	1
All	**17**	**19**	**36**

Table 2.5-2 — Respondents that have an Operational State Estimator

Seventy-five percent (9 out of 12) of respondents without a state estimator plan to add one in the future. Ninety-one percent (32 out of 35) of respondents with an operational state estimator rate it "essential" for situational awareness; 3 respondents, including 1 reliability coordinator, rated the state estimator "desirable."

Applications that Use the State Estimator Solution

The state estimator solution is a base case for contingency analysis for 94 percent (33 out of 35) of respondents and a base case for power flow for 97 percent (34 out of 35) of respondents. All RC respondents use the state estimator solution as a base case for contingency analysis and power flow. Eleven percent of respondents (4 out of 35) use the state estimator solution in locational marginal pricing applications. More than half of the 36 respondents who use state estimators use the base-case solution in offline power-flow applications. Twenty-nine percent (10 out of 35) of those who employ state estimators use the base case in their security-constrained economic dispatch application (see Table 2.5-3). Because multiple applications depend on the state estimator solution, it is essential that the state estimator be available and able to produce an accurate solution.

What Applications Use the State Estimator Solution as a Base Case?	RC	Other	Total
Contingency analysis	16	17	33
Voltage stability analysis	6	5	11
On-line/operator power flow	16	18	34
Off-line power flow	13	9	22
Study real-time maintenance	8	7	15
Locational marginal pricing	3	1	4
Security-constrained economic dispatch	7	3	10
Other(s)	2	2	4
Total	**16**	**19**	35

Table 2.5-3 — Applications that use State Estimator Solution as a Base Case

Respondents also use their state estimator solutions as input to monitoring tools. Table 2.5-4 shows the monitoring tools/applications that depend on the state estimator solution. RTBPTF believes that, as the performance of state estimators continues to improve, use of the state estimator solution in monitoring tools will increase. Table 2-5.4 shows the number of respondents whose state estimators interface with monitoring tools (i.e., driving the alarm tools application) Table 2.5-5 summarizes the usage of state estimators as monitoring tools. Most respondents use their state estimators to monitor MVA/Ampere loadings and low and high bus voltages.

Applications are Interfaced or Integrated With Your State Estimator	RC	Other	Total
SCADA	15	15	**30**
Alarm tools	15	13	**28**
Monitoring and visualization tools	15	13	**28**
Total	**16**	**19**	**35**

Table 2.5-4 — State Estimator Interface with Other Applications

Usage of State Estimator as a Monitoring Tool	RC	Other	Total
MVA/ampere loading	15	18	**33**
Low bus voltage	15	18	**33**
High bus voltage	15	18	**33**
Voltage drop	11	5	**16**
Voltage node angle separation	10	7	**17**
Other(s)	2	2	**4**
Total	**15**	**19**	**34**

Table 2.5-5 — State Estimator Used as Monitoring Tool

State Estimator Features

The survey asked respondents to describe features of their state estimators. The subsections below describe the data reported.

Customization & Application Integration

Table 2-5.6 summarizes the degree to which respondents' state estimators are customized. Table 2.5-7 summarizes responses regarding who developed state estimators for respondents. Table 2.5-8 summarizes the degree of state estimator integration. The results in these tables reflect the fact that good state estimators are commercially available; that is, major SCADA/EMS vendors can provide viable state estimators off the shelf with some customization.

Degree of State Estimator Customization	RC	Other	Total
Off the shelf with some customization	12	7	**19**
Off the shelf	3	8	**11**
Highly customized	2	3	**5**
Total	**17**	**18**	**35**

Table 2-5.6 — Degree of State Estimator Customization

State Estimator Developer	RC	Other	Total
Supplied by your SCADA/EMS vendor	15	16	**31**
Developed in house		2	**2**
Supplied by other vendor	2		**2**
Total	**17**	**18**	**35**

Table 2.5-7 — State Estimator Developer

Degrees of State Estimator Integration	RC	Other	Total
Fully integrated with your production SCADA/EMS system	15	18	**33**
Interfaced to your SCADA/EMS system	1		**1**
Stand alone	1		**1**
Total	**17**	**18**	**35**

Table 2.5-8 — Degree of State Estimator Integration

Algorithm Characteristics

The survey asked respondents whether their state estimators solve in one or two passes. Table 2.5-9 summarizes the responses, which indicate that the industry favors using a single-pass over a two-pass solution. According to Koress,[48] single-pass methods perform one estimation that simultaneously addresses internal and external networks. Among the drawbacks of single-pass state estimators are numerical instability problems and "smearing" of bad external system data to the internal system. An alternative one-pass method solves this problem by using a set of critical external pseudo-measurements. The two-pass method involves two state estimations: one for the internal system and another for the external system or for the entire system. Some versions of the two-pass state estimator require a load-flow study for the external system. Both two-pass approaches reduce the effects of boundary errors in the internal system solution by properly weighting the external pseudo-measurements, but they may result in very high or negative loads and generations in the external system.

State Estimator Algorithm	RC	Other	Total
Single Pass (Observable/internal network and non-observable/external network solved together)	12	12	24
Two-Pass (Observable/internal network and non-observable/external network solved separately)	5	6	11
Total	**17**	**18**	**35**

Table 2.5-9 — State Estimator Algorithm

The survey asked respondents how their state estimators handle zero-injection buses. Table 2.5-10 summarizes the results. Zero-injection buses are more commonly treated as high-confidence bus-injection measurements than as hard constraints.

[48] Koress, George N. 2002. "A Partitioned State Estimator for External Network Modeling," *IEEE Transactions on Power Systems*, Vol. 17, No. 3, August.

How Does Your State Estimator Treat Zero-Injection Buses?	RC	Other	All
Hard constraints	5	6	11
High-quality/confidence bus-injection measurements	11	11	22
Total	**16**	**17**	**33**

Table 2.5-10 — Treatment of Zero-Injection Buses

Convergence Tolerance Parameters

The survey asked respondents to identify their voltage-magnitude convergence-tolerance criteria (per unit) for their internal/observable systems (see Table 2.5-11) and for their external/unobservable systems (see Table 2-5.12).

Data	RC	Other	All
Average	0.0053	0.0253	0.0145
Median	0.0050	0.0099	0.0065
Max	0.0110	0.1000	0.1000
Min	0.0001	0.0010	0.0010
Std Dev	0.0042	0.0373	0.0270
Count	14	12	26

Table 2.5-11 — Voltage-Magnitude Convergence-Tolerance Criteria (per unit) for Internal/Observable System

Data	RC	Other	All
Average	0.0085	0.0226	0.0140
Median	0.00500	0.0100	0.0080
Max	0.0500	0.1000	0.1000
Min	0.0001	0.0010	0.0001
Std Dev	0.0126	0.0325	0.0230
Count	14	9	23

Table 2-5.12 — Voltage-Magnitude Convergence-Tolerance Criteria (per unit) for External/Unobservable System

The survey asked respondents to quantify their voltage-angle convergence-tolerance criteria (in radians) for their internal/observable systems (see Table 2.5-13) and their external/unobservable systems (see Table 2.5-14).

Data	RC	Other	All
Average	0.0078	0.0219	0.0143
Median	0.0050	0.0080	0.0063
Max	0.0350	0.1000	0.0100
Min	0.0005	0.0010	0.0001
Std Dev	0.5330	0.0369	0.0262
Count	14	12	26

Table 2.5-13 — Voltage-Magnitude Convergence-Tolerance Criteria (radians) for Internal/Observable Systems

Data	RC	Other	All
Average	0.0087	0.0189	0.0127
Median	0.0050	0.0100	0.0065
Max	0.0500	0.1000	0.1000
Min	0.0000	0.0001	0.0001
Std Dev	0.0124	0.0311	0.0216
Count	14	9	23

Table 2.5-14 — Voltage-Magnitude Convergence-Tolerance Criteria (radians) for External/Unobservable Systems

Periodicity of State Estimator Execution

The survey asked respondents to describe by what means they trigger their state estimators to run. Table 2.5-15 summarizes the data regarding triggering methods, and Table 2.5-16 details the responses from RCs only. The data in Table 2.5-15 show that 100 percent (35 out of 35) of respondents use periodic triggers for their state estimators. Seventy-one percent (25 out of 35) of respondents, including 71 percent (12 out of 17) of RCs, use manual triggers. Fifty-one percent (18 out of 35), including 59 percent (10 out of 17) of the RCs, use SCADA event triggers (i.e., breaker trips, analog rates of change).

State Estimator Triggering Method	RC	Other	All
Periodic Trigger	17	18	**35**
Manual Trigger	12	13	**25**
SCADA Event Trigger (change of status, rate-of-change, etc.)	8	10	**18**
Disturbance Event Trigger	1	3	**4**
Other(s)	1	2	**3**

Table 2.5-15 — State Estimator Triggering Method

State Estimator Trigger Type Used	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Periodic Trigger	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	18	**35**
Manual Trigger	X		X	X	X	X	X		X	X	X	X	X	X				13	**25**
SCADA Event Trigger	X	X	X	X	X	X	X	X										10	**18**
Other(s)		X																2	**3**
Disturbance Event Trigger	X																	3	**4**

Table 2.5-16 — State Estimator Triggering Method (detailed RC responses)

Respondents using a periodic trigger were asked to quantify it in seconds. Table 2.5-17 shows the descriptive statistics for state estimator trigger periodicity in seconds. Table 2.5-18 shows the frequency distribution for the same data. Macedo (2004)[49] says that state estimators should be triggered to execute every 2 minutes.

SE Trigger Periodicity (seconds)	RC	Other	All
Average	319	473	**396**
Median	300	300	**300**
Max	1,800	1,800	**1,800**
Min	30	60	**30**
Std Dev	399	506	**455**
Count	17	17	**34**

Table 2.5-17 — State Estimator Periodic Trigger Descriptive Statistics

[49] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

SE Trigger Periodicity (seconds)	RC	Other	All
30	1		1
60	2	2	4
90	2		2
120		2	2
180	1	1	2
300 (5 minutes)	9	8	17
420	1		1
900		2	2
1,500		1	1
1,800	1	1	2

Table 2.5-18 — State Estimator Periodic Trigger Frequency Distribution (seconds)

Respondents who use a manual trigger were asked what criteria they use to decide to trigger their state estimators. Table 2.5-19 shows the results for all respondents. Table 2.5-20 shows the responses for reliability coordinators only.

Trigger	RC	Other	All
After an invalid/suspect solution	10	7	**17**
After a system event	6	9	**15**
After a manual override of data	8	2	**10**
Other(s)	6	2	**8**
Based on a schedule	3	1	**4**

Table 2.5-19 — State Estimator Manual Trigger Criteria

If You Use a Manual Trigger, What Criteria do You Use to Decide to Manually Trigger SE?	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	Other	All
After an invalid/suspect solution	X	X	X	X	X	X	X	X	X	X						7	**17**
After a system event	X	X	X	X	X							X				9	**15**
After a manual override of data	X	X	X		X	X		X	X	X						2	**10**
Other(s)				X		X	X				X		X	X		2	**8**
Based on a schedule	X	X													X	1	**4**

Table 2.5-20 — State Estimator Manual Trigger Criteria (RCs Only)

State Estimator Execution Time (Performance)

The survey asked how long (wall clock time) it usually takes respondents' state estimators to solve. The average state estimator execution time for the 34 respondents to this question ranges from 1 second to 2 minutes. The average execution time for all respondents is about 20 seconds. The median execution time was 10.5 seconds for all respondents and 10 seconds for RC respondents. Average execution times are 10 seconds or shorter for half of the respondents' state estimators (17 out of 34), including 58 percent (10 out of 17) of the RCs' applications. Table 2.5-21 summarizes the results. Table 2.5-22 shows the frequency distribution for the same information.

State Estimator Solution Time (Wall Clock)	RC	Other	All
Average	21.0	19.4	**20.2**
Median	10.0	15.0	**10.5**
Max	120.0	60.0	**120.0**
Min	2.0	1.0	**1.0**
Std Dev	28.9	17.9	**23.7**
Count	17.0	17.0	**34.0**

Table 2.5-21 — State Estimator Solution Time (wall clock time in seconds) Descriptive Statistics

State Estimator Solution Time (Wall Clock)	RC	Other	All
1-10	10	7	17
11-20	4	6	10
21-30	1	1	2
>30	2	3	7
Total	17	17	34

Table 2.5-22 — Frequency Distribution for State Estimator Solution Time (wall clock time, in seconds)

State Estimator Convergence Rate and Availability

The survey asked respondents to identify their convergence rate metrics and tools. Table 2.5-23 summarizes the results. Fifty percent (17 out of 34) of the respondents, including 53 percent (9 out of 17) of the RC respondents, have state estimator convergence rate metrics as well as tools to compute these metrics.

Do You Have Convergence Rate Metrics and Tools?	RC	Other	All
Yes	9	8	**17**
No	8	9	**17**
Total	17	17	**34**

Table 2.5-23 — State Estimator Convergence Rate Metrics and Tools

The survey asked respondents to indicate how their convergence rates were measured. Of those that responded, 50 percent (8 out of 16), compute the state estimator convergence rate automatically. Table 2.5-24 summarizes the responses. Table 2.5-25 summarizes the time period(s) for which state estimator convergence rates are measured, with detailed data for the reliability coordinator respondents. For respondents that measure state estimator convergence rate, the most common time interval is 1 month. Forty-four percent (4 out of 9) of the reliability coordinator respondents track state estimator convergence rate over multiple time intervals.

How is Your State Estimator Convergence Rate Measured?	RC	Other	All
Automatically	4	4	**8**
Manually	2	3	**5**
Other(s)	3		**3**
Total	9	7	**16**

Table 2.5-24 — State Estimator Convergence Rate Measurement

For What Time Periods is Your State Estimator Convergence Rate Measured? (Please check all that apply and specify a % solution rate for that time period.)	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	Others	All
Previous Month(s)	X		X			X	X			4	**8**
Previous Hour(s)	X	X	X		X					2	**6**
Previous Week(s)	X	X								1	**3**
Previous Year(s)	X	X						X		0	**3**
Rolling Time Period(s)				X						1	**2**
Selected Time Period(s)				X					X	1	**3**

Table 2.5-25 — Time Periods for State Estimator Convergence Rate Measurements

The survey asked the approximate distribution of respondents' state estimator availability. Table 2.5-26 summarizes the average percentage of time during which state estimators are not available within each duration range. The average period during which state estimator solutions are unavailable is 15 minutes or less for more than 95 percent of all respondents and more than 93 percent of RCs. Note that most respondents -- sixty percent (9 out of 15), and 78 percent (7 out of 9) of RC respondents -- estimate unavailability periods rather than computing them from historical data.

Duration of state estimator unavailability — distribution	RC	Other	All
≤ 15 minutes	93.6	98.5	95.5
15 - 30 minutes	4.1	1.2	3.0
30 - 60 minutes	1.0	0.0	0.7
1 - 4 hours	0.5	0.3	0.4
> 4 hours	0.8	0.0	0.4

Table 2.5-26 — Frequency Distribution of State Estimator Unavailability

The survey asked respondents to indicate how long the state estimator would have to be unavailable to have "significant impact" on their system operations. Table 2.5-27 summarizes the responses. Thirteen percent (2 out of 15) of respondents, including 11 percent (1 out of 9) of RCs, consider unavailability of up to 30 minutes as having no significant impact on operations. Eighty-nine percent (8 out of 9) of the RC respondents cited a "reliability requirement" as the basis for their state estimator unavailability metric. All 6 of the other respondents cited an "internal policy requirement" as the basis for their state estimator unavailability metric. Forty-four percent (4 out of 9) of the RC respondents and 50 percent (3 out of 6) of the other respondents cited market application requirements.

What is the Length of Unavailability That You Consider to Be a Significant Impact on Your System Operation? More than ...	RC	Other	All
1 minute		1	1
10 minutes	1		1
15 minutes		1	1
20 minutes	2	3	5
30 minutes	5		5
60 minutes	1	1	2
Total	**9**	**6**	**15**

Table 2.5-27 — State Estimator Unavailability Considered "Significant" Impact on Operations

Table 2.5-28 summarizes the frequency of state estimator failures that respondents perceive as having a "significant" impact on system operations. Eighty-one percent (13 out of 16) of respondents, including 78 percent (7 out of 9) of RC respondents, experience either occasional or rare state estimator failures that have a significant impact on their operations. Nineteen percent (3 out of 16) of respondents, including 22 percent (2 out of 9) of RC respondents have frequent or very frequent state estimator failures that impact system operations.

Which Best Describes the Frequency of State Estimator Failures That Have a Significant Impact on Your System Operation?	RC	Other	All
Rare — At least one per year on average	3	5	**8**
Occasional — At least one per month on average	4	1	**5**
Very frequent — At least one per day on average	1	1	**2**
Frequent — At least one per week on average	1		**1**
Total	**9**	**7**	**16**

Table 2.5-28 — Frequency of State Estimator Unavailability Considered "Significant" Impact on Operations

State Estimator Solution Quality (Accuracy)

One hundred percent of respondents can detect and identify bad analog measurements and remove them from the state estimator measurement set. The survey asked respondents to quantify the real/reactive power mismatch tolerance criteria for their internal/observable systems. Respondents report a 0.05-170 MW real power mismatch tolerance range and a 0.001-500 Mvar reactive power mismatch tolerance range. The average real and reactive mismatch tolerance criteria were 35 MW and 69.5 Mvar, respectively. Table 2.5-29 summarizes the state estimator convergence criteria for internal system MW mismatch. Table 2.5-30 summarizes the state estimator convergence criteria for internal system Mvar mismatch. The results in Table 2.5-29 and Table 2.5-30 are suspect because zero-injection buses are not treated consistently by all respondents (see Table 2.5-10). Respondents that treat zero-injection buses as hard constraints would be expected to indicate very low real/reactive mismatch tolerances whereas respondents treating zero-injection buses as high-confidence measurements would be expected to have reasonable real/reactive mismatch tolerance values.

Data	RC	Other	All
Average	43.20	17.10	35.00
Median	30.00	1.00	15.00
Max	170.00	50.00	170.00
Min	0.05	0.10	0.05
Std Dev	51.10	25.50	45.60
Count	13.00	6.00	19.00

Table 2.5-29 — State Estimator Convergence Criteria for Internal System MW Mismatch

Data	RC	Other	All
Average	93.700	16.300	69.500
Median	50.000	1.000	40.000
Max	500.000	50.000	500.000
Min	0.001	0.100	0.001
Std Dev	144.300	22.700	124.000
Count	11.000	5.000	16.000

Table 2.5-30 — State Estimator Convergence Criteria for Internal System Mvar Mismatch

The survey asked respondents to quantify the real/reactive power mismatch tolerance criteria for their external/unobservable systems. Respondents report a 0.05-999 MW real power mismatch tolerance range and a 0.001-9999 Mvar reactive power mismatch tolerance range. The average real and reactive mismatch tolerance criteria were 614.7 MW and 665.7 Mvar respectively. Table 2.5-31 summarizes the state estimator convergence criteria for external system MW mismatch. Table 2.5-32 summarizes the state estimator convergence criteria for external system Mvar mismatch. As in the case for the internal/observable system, the results in Table 2.5-31 and Table 2.5-32 are suspect because zero-injection buses are not treated consistently by all respondents (see Table 2.5-10). Respondents that treat zero-injection buses as hard constraints would be expected to indicate very low real/reactive mismatch tolerances values whereas respondents that treat zero-injection buses as high-confidence measurements would be expected to have reasonable real/reactive mismatch tolerance values.

Macedo (2004)[50] states that state estimator MVA mismatch should be less than 10 MVA. He does not distinguish between internal and external systems.

Data	RC	Other	All
Average	138.40	1,431.10	614.70
Median	40.00	1.00	10.00
Max	999.00	9,999.00	9,999.00
Min	0.05	1.00	0.05
Std Dev	279.00	3,778.00	2,283.00
Count	12.00	7.00	19.00

Table 2.5-31 — State Estimator Convergence Criteria for External System MW Mismatch

Data	RC	Other	All
Average	219.200	1,431.100	665.700
Median	70.000	1.000	10.000
Max	999.000	9,999.000	9,999.000
Min	0.001	1.000	0.001
Std Dev	370.000	3,778.000	2,280.000
Count	12.000	7.000	19.000

Table 2.5-32 — State Estimator Convergence Criteria for External System Mvar Mismatch

Table 2.5-33 summarizes respondents' state estimator solution quality (accuracy) metrics, showing detailed responses for RCs. The most commonly used state estimator solution quality metric, cost index, is used by 45 percent (10 out of 22) of all respondents and 58 percent (7 out of 12) of RC respondents. The second most commonly used metric is Chi-Squared criteria, used by 36 percent (8 out of 22) of all respondents and 42 percent (5 out of 12) of RC respondents. These metrics are a basis for RTBPTF's recommendation for operating guidelines related to state estimator solution quality.

[50] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

What is Your Metric for Assessing the Accuracy of the Results of Your State Estimator Application? (Please check all that apply.)	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	Other	Total
Use cost index as a performance indicator	X	X	X	X			X				X	X	3	**10**
Use Chi-Squared criteria as performance indicator		X	X			X	X	X					3	**8**
Use measurement error/bias analysis as a performance indicator			X						X	X			4	**7**
Use average residual value as a performance indicator	X												1	**2**
Other(s)	X	X			X								3	**6**

Table 2.5-33 — State Estimator Solution Quality (Accuracy) Metrics

Table 2.5-34 summarizes respondents' methods for assessing state estimator solution quality. These methods are not formalized assessment processes.

What is Your Method for Assessing the Accuracy of the Results of Your State Estimator Application?	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	Other	All
Continually monitor and minimize the amount of bad data detected by correcting model, telemetry, and bad statuses	X	X	X	X	X	X	X	X	X	7	**16**
Compare critical telemetry with the state estimator solution (ties, major lines, large units, etc.)	X	X	X	X	X	X		X	X	7	**15**
Use measurement error/bias analysis to detect and resolve telemetry and model problems			X	X	X	X	X	X		8	**14**
Periodically review all stations to correct high residuals and minimize all residuals as much as reasonably possible	X	X	X			X	X		X	5	**11**
Compare contingency analysis results to actual system	X	X	X	X	X	X	X		X	2	**10**
Compare power-flow results to actual system	X	X		X	X	X		X		2	**8**
Compare state estimator actual violations to see if they closely match actual SCADA violations	X	X	X	X	X		X			2	**8**
Compare state estimator total company load/ generation/ interchange integrated over time to see if it closely matches billing metering	X	X	X							0	**3**
Others										1	**1**

Table 2.5-34 — Methods for Assessing State Estimator Solution Quality (Accuracy)

Measurement weights (confidences) are important parameters used in the state estimator application that could significantly affect its solution. The survey asked respondents to define weights for telemetered measurements. Table 2.5-35 shows that 78 percent (8 out of 11) of all respondents, including 80 percent (4 out of 5) of RC respondents, use individually defined weights for at least some of the telemetered measurements used by their state estimators. Thirty-six percent (4 out of 11) of all respondents, including 60 percent (3 out of 5) of RC respondents, use globally defined weights for at least some of the telemetered measurements used by their state estimators. The survey also asked respondents to define measurement weights for non-telemetered measurements. Table 2.5-36 summarizes the responses. Fifty-five percent (6 out of 11) of all respondents, including 60 percent (3 out of 5) of RC respondents, use globally defined weights for at least some of the non-telemetered measurements used by their state estimators (i.e., modeled loads and generator outputs). Fifty-five percent (6 out of 11) of the respondents, including 60 percent (3 out of 5) of RC respondents, use individually defined weights for at least some of the non-telemetered measurements used by their state estimators (i.e., modeled loads and generator outputs).

How do You Define Measurement Weights for Telemetered Measurements?	RC01	RC02	RC03	RC04	RC05	Others	Total
Measurements have individually defined weights		X	X	X	X	4	**8**
Globally defined weights by measurement type (e.g., line measurements, transformer MW/Mvar)	X		X		X	1	**4**
Others						1	**1**

Table 2.5-35 — Weights for Telemetered Measurements

How do You Define SE Measurement Weights for Non-Telemetered Measurements? (Please check all that apply.)	RC01	RC02	RC03	RC04	RC05	Others	All
Globally defined weights by type (e.g., non-telemetered loads, non-telemetered generators)	X		X		X	3	**6**
Measurements have individually defined weights			X	X	X	3	**6**
Other(s)		X					**1**

Table 2.5-36 — Weights for Non-Telemetered Measurements

The survey asked respondents to characterize their basis for assigning weights to model measurements. Table 2.5-37 summarizes the responses for SCADA analog measurements (excluding measurements from ISN and other data links). Forty-five percent (5 out of 11), including 60 percent (3 out of 5) RC respondents, use generic percentage metering errors as the basis for weights applied to at least some analog values used by their state estimators. Twenty-seven percent (3 out of 11), including 40 percent (2 out of 5) of RC respondents, use actual meter accuracies as the basis, and 27 percent (3 out of 11) use other methods besides actual meter accuracies or generic meter error percentages.

What is the Basis for Your SCADA Analog Measurement Weights (excluding measurements from ISN and other data links)?	RC01	RC02	RC03	RC04	RC05	Others	All
Generic percentage meter error for each measurement type	X			X	X	2	**5**
Actual meter accuracies associated with each individual measurement						3	**3**
Other(s)		X	X			1	**3**

Table 2.5-37 — Basis for SCADA Analog Measurement Weights

Using State Estimator to Monitor External Facilities

Monitoring external facilities using the state estimator is highly dependent on the modeling practices related to external facilities. State estimator solution quality including external facilities depends on the accuracy with which external facilities are modeled. Section 4.1, Model Characteristics, and Section 4.2, Modeling Practices and Tools, discuss external system modeling practices in detail.

The external network models that are currently in use could affect the quality of state estimator solutions by:

- **Propagation of errors into the internal model solution from the external model solution**. This concern applies to one-pass state estimators if the external network model solution is mainly based on forecasted and/or pseudo-measurements rather than telemetered data. The external network model equivalencing methodology could also cause errors to propagate. For systems that use a two-pass state estimator, there could be boundary problems (between the internal/observable solution and the external/unobservable solution) that could cause the total network solution to not converge.

- **Measurement density in the external system**. Findings in Section 4.1 indicate that many buses in external models are measurement unobservable. The low values for the external-status-point-to-external-bus ratios for many respondents (i.e., less than one status point per bus) indicates that many external buses do not have telemetered breaker/switch information, which implies a bus-branch type external model (i.e., a planning model) for many buses. The lack of real-time telemetry data in MISO's external model was one of the contributing factors in the 2003 blackout. The *Outage Task Force Final Blackout Report* indicates that MISO was using a static bus-branch network model in parts of its external model. When the Stewart- Atlanta 345-kV line tripped (monitored by the PJM reliability coordinator), MISO's state estimator did not know the line had gone out of service. This led to a data mismatch that prevented MISO's state estimator from computing a solution that could be used by its real-time contingency analysis application.[51]

- **Convergence issues related to external models and/or telemetry data for external model**. Measurements for the external network model usually originate from ICCP (or equivalent) data links. Therefore, data availability depends on data-link availability. Another factor is the time skew of data supplied by the external network model measurements; time skew is highly dependent on the periodicity of the data-link data.

- **Interchange transaction impacts.** The impact of interchange transactions, especially for the external portion of the model, could greatly affect the state estimator solution.

- **Throughput because of external model expansion/detail**. Adding detail or expanding the external network model could affect the throughput (execution time) of the state estimator application.

In response to the 2003 blackout, many survey respondents are expanding and/or adding more detail to their external network models. As mentioned in Section 4.1, Model Characteristics, approximately 88 percent (15 out of 17) of RC respondents and 75 percent (18 out of 24) of other respondents indicate that in the coming year they plan to make "major" changes to their network models above and beyond what is considered "routine" model maintenance. Table 2.5-38 summarizes the types of changes planned. These changes will greatly impact state estimator solution quality. The observations cited in Table 2.5-38 suggest that most near-term major changes will be related to external network model improvements. For RCs, these types of changes will enhance wide-area analysis capabilities provided by the reliability analysis applications recommended by Macedo (2004)[52.]

[51] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 46.

[52] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

Major Model Changes in Coming Year	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	Others	Total
Adding breaker/switch detail to the external model	X	X	X	X			X	X	X							7	**14**
Adding breaker/switch detail to the internal model	X	X	X	X	X											7	**12**
Adding extensive telemetry to the external model	X	X	X			X	X	X	X							6	**13**
Adding extensive telemetry to the internal model	X	X		X	X	X							X			3	**9**
Adding lower voltage detail to the external model	X									X						3	**5**
Adding lower voltage level detail to the internal model	X	X	X	X												4	**8**
Adding one or more control areas to the external model	X					X										3	**5**
Creating a new external model	X									X	X	X			X	10	**15**
Others			X		X						X			X		5	**9**

Table 2.5-38 — Major Model Changes Planned for Coming Year

The survey asked respondents to characterize their basis for assigning weights to model measurements from ISN and other data links (i.e., external model measurements). Table 2.5-39 summarizes the responses, showing that 78 percent (8 out of 11) of all respondents and 60 percent (3 out of 5) RC respondents use generic metering error percentages as the basis. Twenty-seven percent (3 out of 11), including 40 percent (2 out of 5) of RC respondents, use something other than generic percentages or actual metering errors as the basis.

What is the Basis for Your Measurement Weights From ISN and Other Data Links?	RC01	RC02	RC03	RC04	RC05	Other	All
Generic percentage meter error for each measurement type	X			X	X	5	**8**
Other(s)		X	X			1	**3**

Table 2.5-39 — Basis for ISN (and other data link) Analog Measurement Weights

Presentation of State Estimator Results

The survey asked respondents to describe how their state estimator solution is presented in visualization tools (i.e., state estimator one-line displays). (Section 2.1, Visualization Techniques, of this report discusses usage and prevalence of state estimator one-line displays.) Of the 35 respondents that have working state estimators, 97 percent (34 out of 35), including 100 percent (17 out of 17) of RC respondents, use some type of state estimator one-line display. Sixty-five percent (22 out of 34) overlay the state estimator values on SCADA one-line displays so that estimated values can be seen along with raw values. Thirty-five percent (12 out of 34) display state estimator results separately from SCADA one-lines. Among RC respondents, 47 percent (8 out of 17) overlay state estimator results on existing SCADA one-line displays, and 53 percent (9 out of 17) display state estimator results on separate one-line displays. Table 2.5-40 summarizes the results.

State Estimator One-Line Displays	RC	Other	All
State estimator one-lines are overlays of SCADA one-lines	8	14	**22**
State estimator one-lines are separate from SCADA one-lines	9	3	**12**
Do not have state estimator one-lines	0	1	**1**
Total	17	18	**35**

Table 2.5-40 — Presentation of State Estimator Results

State Estimator Maintenance/Troubleshooting Practices

The majority of respondents can notify operators and control room staff of a state estimator failure. State estimator status is presented primarily via alarm tools and physical displays although a few respondents can page and send email.

The survey asked respondents whether they have a process to investigate and de-bug unsolved/non-converged and bad/inaccurate state estimator solutions. Ninety-four percent (29 out of 31) of those that responded, including 94 percent (15/16) of RC respondents, investigate unsolved state estimator solutions. Table 2.5-41 summarizes the responses.

Do You Investigate Unsolved or Non-Converged State Estimator Solutions?	RC	Other	All
Yes	15	14	**29**
No	1	1	**2**
All	16	15	**31**

Table 2.5-41 — Investigation of Unsolved or Non-Converged State Estimator Solutions

The survey also asked respondents whether their operators attempt to resolve state estimator problems prior to notifying support personnel. Table 2.5-42 summarizes the results. Fifty-three percent (15 out of 28) of all respondents, including 60 percent (9 out of 15) of RC respondents, have operators attempt to resolve state estimator convergence problems prior to notifying EMS support personnel.

Do Operators Attempt to Resolve State Estimator Problems Prior to Notifying Support?	RC	Other	All
Yes	9	6	**15**
No	6	7	**13**
Total	15	13	**28**

Table 2.5-42 — State Estimator Problem-Resolution Practices

The survey asked respondents about state estimator maintenance and support. Table 2.5-43 summarizes the responses. The table illustrates that 100 percent (28 out of 28) of all respondents, including 100 percent (15 out of 15) of RC respondents maintain their state estimators with in-house staff. However, 18 percent (5 out of 28), including 27 percent (4 out of 15) of RC respondents, use vendor staff in addition to in-house staff for support.

Who Maintains Your State Estimator?	RC	Other	All
In-House Staff	15	13	**28**
Vendor Staff	4	1	**5**

Table 2.5-43 — State Estimator Maintenance and Support

The survey asked respondents whether they continuously monitor the status of their state estimators (i.e., 24 hours per day, 7 days per week, 365 days per year). Table 2.5-44 summarizes the responses. Seventy-five percent (27 out of 36) of all respondents that have operational state estimators responded to this question. Of those that responded, 89 percent (24 out of 27), including 93 percent (14 out of 15) of RC respondents, continuously monitor state estimator status 24 x 7 x 365. The respondents were also asked whether their state estimator support personnel are available continuously (24 x 7 x 365). There were 28 respondents to this question, including 15 RCs; Table 2.5-45 summarizes the results. Ninety-three percent (26 out of 28) of all respondents, including 93 percent (14 out of 15) of RC respondents, have state estimator support personnel available continuously.

Is the Status of Your State Estimator Monitored Continuously (24 x 7 x 365)?	RC	Other	All
Yes	14	10	**24**
No	1	2	**3**
Total	**15**	**12**	**27**

Table 2.5-44 — State Estimator Application Monitoring

Are Your State Estimator Support Personnel Available Continuously (24 x 7 x 365)?	RC	Other	All
Yes	14	12	**26**
No	1	1	**2**
Total	**15**	**13**	**28**

Table 2.5-45 — State Estimator Support Personnel Availability

Table 2.5-46 summarizes how support personnel are notified of state estimator problems. A majority of respondents, 79 percent (22 out of 28), including 87 percent of RC respondents, send an alarm to their operators. The operators then contact support personnel as needed to correct the problem. Sixty percent (17 out of 28) of all respondents, including 60 percent of RC respondents, have support personnel on call who can connect to the EMS remotely after business hours to fix reported problems. Only 7 respondents, which included 6 RCs, have support personnel on duty that continually monitor the state estimator.

How Are Your State Estimator Support Personnel Notified of Problems? (Please check all that apply.)	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	Other	All
The operator receives an alarm and then calls for support personnel.	X	X	X	X	X	X	X	X		X	X	X	X	X		9	**22**
Support personnel are on call and connect remotely after business hours to fix reported problems.	X	X		X	X		X	X	X			X		X		8	**17**
Support personnel are on call and report on site after business hours to fix reported problems.	X	X	X		X			X			X		X	X		4	**12**
Support personnel are automatically paged by the application(s).	X	X	X	X	X	X	X									3	**10**
Support personnel are staffed on shift and monitor applications continuously.	X	X	X	X		X				X						1	**7**
Other(s)															X	0	**1**

Table 2.5-46 — State Estimator Support Personnel Notification Methods

Recommendations for New Reliability Standards

The state estimator is mainly used:

- as a base case for reliability analysis applications (e.g., contingency analysis, power flow), and
- as input to other operator monitoring tools (e.g., alarm, wide-area visualization).

Wollenberg (2006)[53] says:

[53] Wollenberg, Bruce. 2006."ERO Standards: What Should They Cover." *IEEE Power & Energy Magazine*, Volume 4 (4), July/August: 96.

> The state estimator is the first of the major application programs that runs as new data are gathered from the power system into an operations computer system. If the state estimator fails, then the remaining applications ([optimal power flow] OPF, security analysis, etc.) cannot be run — the operator is blind. To quote Brian Stott, "By now, it ought to be (and is not) a SCANDAL if a company's state estimator does not produce a reliably accurate real-time power system model virtually 100% of the time." So what does it take to achieve a 100% reliable state estimator? First it takes a well-thought-out and maintained metering system, a well-maintained communications system, a constantly updated database containing the power system model, and, last of all, a state estimator algorithm designed not to fail when some critical measurements are missing.

The results of the RTBPTF survey detailed in the previous section support the assertion of Macedo (2004)[54] that a state estimator is a minimum requirement, i.e., an essential tool for operators. Figure 2.5-1 shows a slide from Macedo (2004) on the topic of network analysis, which implies that a state estimator should execute every two minutes and should have a solution accuracy of less than 10 MVA mismatch. RTBPTF agrees with Macedo's assessment that a state estimator is a minimum requirement (i.e., a critical real-time tool) but does not agree that the state estimator needs to execute every 2 minutes at a minimum. In lieu of measuring the triggering periodicity of state estimator, RTBPTF recommends measuring state estimator availability (for a given, reasonable periodicity required by other reliability analysis applications). RTBPTF also recommends measuring state estimator solution quality. RTBPTF believes that state estimator availability and adequate solution quality are measures that can ensure a robust and accurate reliability monitoring tool for operators. The state estimator availability and state estimator solution quality recommendations are discussed in detail in the following subsections below.

[54] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

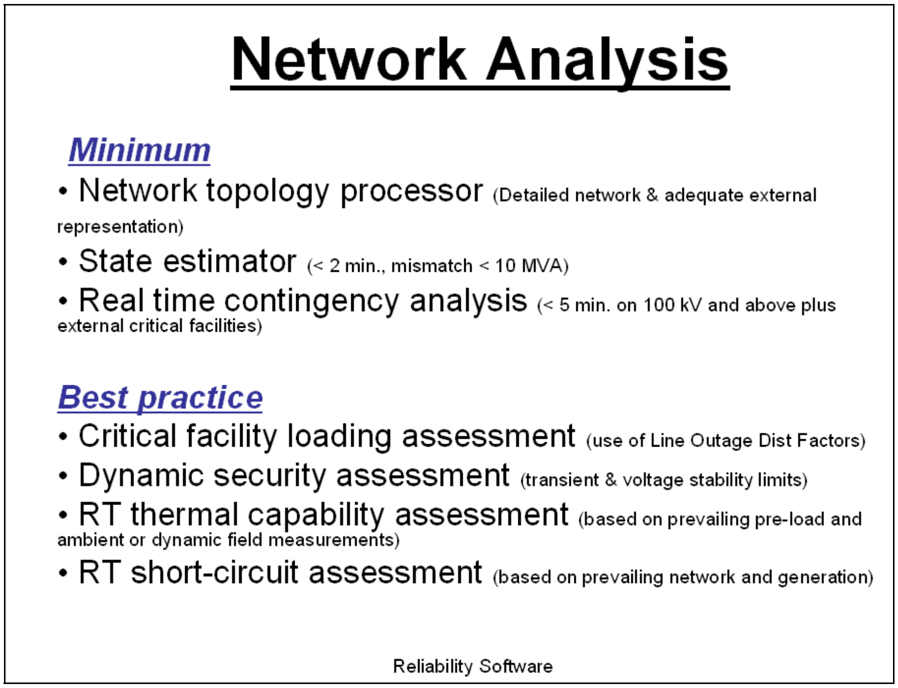

Figure 2.5-1 — Copy of Slide on Network Analysis (Macedo 2004)

Recommendation – S1

Mandate the following reliability tools as mandatory monitoring and analysis tools

- Alarm Tools
- Telemetry Data Systems
- Network Topology Processor
- State Estimator
- Contingency Analysis

State Estimator: Mandatory Monitoring and Analysis Tool

Survey results indicate that state estimators are inherently delivered as part of commercially available modern SCADA/EMS systems. RTBPTF believes that a state estimator is essential for operators to monitor and maintain the reliability of the bulk electric system. Existing NERC reliability standards implicitly assume the use of state estimators to aid RCs and TOPs in maintaining situational awareness for the bulk electric system. Standard IRO-002 (Requirement R7) states "[e]ach Reliability Coordinator shall have ***adequate analysis tools*** [emphasis added] such as ***state estimation*** [emphasis added], pre and post-contingency analysis capabilities (thermal, stability, and voltage), and wide area overview displays." Specifying the state estimator as part of the Reliability Toolbox[55] clarifies current NERC reliability standards by indicating that the state

[55] See the Reliability Toolbox Rationale and Recommendation section.

estimator, as defined, is mandatory. It also clarifies the term "adequate analysis tools."

Recommendation – S11

Specify and measure minimum availability for state estimator, including a requirement for solution quality.

State Estimator Availability

If the state estimator is mandatory for bulk electric system situational awareness, it must be highly available and redundant. Awareness of state estimator availability is discussed in the recommendations in Section 5.4, Critical Applications Monitoring. However, a more detailed awareness (via a requirement for state estimator availability) of state estimator availability is necessary than what is described in Section 5.4; in particular, a metric measuring "adequate" availability should be established.

RTBPTF Recommendation

RTBPTF recommends adding the following new requirement to Standard TOP-006 to measure state estimator availability:

PR2. State Estimator Availability. Each reliability coordinator and transmission operator shall operate its state estimator based on the following metrics:

a. State Estimator Availability Metric 1 (SEA1): Each reliability coordinator and transmission operator shall operate such that its state estimator shall have at least one converged solution (i.e., produce a state-estimate solution) for at least 97.5 percent of 10-minute clock periods (i.e., six non-overlapping periods per hour) during a calendar month.

b. State Estimator Availability Metric 2 (SEA2): Each reliability coordinator and transmission operator shall also operate such that its state estimator shall have at least one converged solution (i.e., produce a state-estimate solution) for every continuous 30-minute interval during a calendar day.

RTBPTF recommends the following measures (see PM2a and PM2b) for the state estimator availability requirements stated above. To validate the effectiveness of the metrics, RTBPTF recommends that a pilot program (or field trial) be conducted to analyze the metrics' effectiveness.

PM3. Measures for State Estimator Availability

PM2.1. The responsible entity shall achieve, at a minimum, Requirement PR2a (SEA1) compliance of 97.5 percent. SEA1 is calculated by converting a state estimator availability ratio to a compliance percentage as follows:

$$SEA1 = \left[1 - \frac{V_{month}}{TP_{month}}\right] * 100$$

$$where:$$

$$V_{month} = \text{Violations per month}$$

$$TP_{month} = \text{Total Periods per month}$$

The violations per month are a count of the number of periods (10-minute clock periods) during which the state estimator does not have at least one converged solution. Each responsible entity shall report the total number of violations for the month.

PM2.2. The responsible entity shall achieve no SEA2 violations per day. One SEA2 violation equates to the state estimator not having at least one converged solution for a period of 30 contiguous minutes (three consecutive 10-minute clock periods), for example, if the state estimator is unavailable continuously for 40 minutes (no converged solution within four consecutive 10-minute clock periods), SEA2=1 for the calendar day or if the state estimator is unavailable continuously for 60 minutes (no converged solution within six consecutive 10-minute clock periods, SEA2=2 for the calendar day. For the purpose of simplicity, when the state estimator remains unavailable through midnight on any day (i.e., through a transition in calendar days), the SEA2 calculation shall be attributed to the previous calendar day. Each responsible entity shall report the total SEA2 violations per month.

Rationale

Recommended requirements PR2a and PR2b measure the availability of the state estimator solution for RCs and TOPs. PR2a is consistent with the NERC mandate for MISO to fully implement and test its state estimator and contingency analysis tools “to ensure they can operate reliably no less than every ten minutes.”[56] Recommended requirement PR2b ensures that the state estimator is unavailable for no more than 30 minutes during a calendar day; this would prevent prolonged periods of unavailability that would negatively affect situational

[56] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 152.

awareness. RTBPTF believes that these availability requirements (SEA1 and SEA2) are consistent with the mandate that operators be aware of potential IROL/SOL violations and have 30 minutes to take the necessary actions to correct/prevent violations. Together with contingency analysis, the state estimator is a critical application that determines potential IROL/SOL violations.

RTBPTF believes that requiring RCs and TOPs to have an available state estimator solution at least once every 10 minutes 97.5 percent of the time will greatly enhance situational awareness. The feasibility of requirements SEA1 and SEA2 is based on the survey data regarding current state estimator availability. Survey data described earlier support the technical feasibility of the state estimator availability requirements as follows:

- The average wall clock (in seconds) execution time for state estimators is 28.9 seconds.
- The average trigger periodicity for state estimator is 319 seconds.
- The most common trigger periodicity for automatic triggers is 5 minutes.
- State estimator unavailability is less than 15 minutes 95.5 percent of the time.
- Eighty-eight percent (15 out of 17) of all survey respondents consider lapses in availability of 30 minutes or longer to significantly impact their operations.

RTBPTF believes that the recommended state estimator availability requirements are reasonable targets based on the survey results.

State Estimator Solution Quality

The state estimator must be highly available and must also be able to provide a reasonable, accurate, robust solution that fulfills the purposes for which it is intended.

RTBPTF Recommendation

RTBPTF recommends that a state estimator solution-quality requirement be established. However, RTBPTF had difficulty formulating specific, technically defensible state estimator solution-quality metrics. The Real-Time Tools Survey did not sufficiently address the issue of the current practices/methods in determining state estimator solution quality. Therefore, RTBPTF believes that state estimator solution-quality metrics warrant further investigation and development. RTBPTF recommends that the SAR process be initiated to define specific, technically defensible state estimator solution-quality metrics.

RTBPTF recommends adding the following new requirement in Standard TOP-006 in order to measure state estimator solution quality:

PR3. State Estimator Solution Quality. Each reliability coordinator and transmission operator shall operate such that its state estimator shall have sufficient solution quality for each converged case.

RTBPTF believes there is no single metric for state estimator solution quality. The survey revealed various methods for assessing state estimator solution quality but these methods were highly dependent on the type of state estimator algorithm being used. RTBPTF recommends that NERC (through the SAR process) develop and define state estimator solution-quality metrics. Pending this development, RTBPTF recommends a possible set of state estimator solution-quality metrics as operating guidelines until mandatory solution-quality metrics are established. Based on the Requirement PR3, RTBPTF recommends the following measure:

PM4. Each reliability coordinator and transmission operator shall have and provide upon request evidence of calculations that demonstrate state estimator solution quality for each converged case.

Rationale

RTBPTF recommends that state estimator availability requirements be augmented by solution-quality requirements to ensure that operators are provided with accurate information so they can be fully aware of the system situation at any given time. Requirement PR3 mandates that RCs and TOPs be cognizant of state estimator solution quality in tandem with complying with the state estimator availability requirement PR2.

Applicability Statement for Recommended Standards

RTBPTF recommends that all RCs and TOPs be required to have a state estimator for monitoring bulk electric system elements and critical reliability parameters as defined in the recommended additions or modifications to the NERC standards applicable to RCs and TOPs. Other responsible entities who use state estimators to support or complement their RCs' ability to operate the bulk electric system reliably in accordance with formal agreements, contracts, or established practices or procedures shall be subject to the same standards for the state estimator as their RCs.

Recommendations for New Operating Guidelines

The subsections below describe recommended guidelines for state estimator operation.

Recommendation – G4

Establish state estimator solution-quality metrics to ensure accurate data and other reliability analysis.

Operating Guidelines for State Estimator Solution Convergence Parameters

It is difficult to recommend specific state estimator voltage and angle convergence tolerances because of the different algorithms employed by different state estimators and the manner in which specific convergence parameters are used in these algorithms. For example, some state estimators check convergence based on changes of the absolute values of voltage magnitudes and voltage phase angles (relative to ground) between successive iterations. At least one vendor bases convergence on changes between successive iterations on voltage magnitude drops and angle differences across branches. There are other approaches as well. Table 2.5-47 summarizes the survey responses for internal and external system voltage and angle convergence tolerances.

Statistic	Internal Voltage Convergence Tolerance	Internal Angle Convergence Tolerance	External Voltage Convergence Tolerance	External Angle Convergence Tolerance
Average	0.0145	0.0143	0.0140	0.0127
Median	0.0065	0.0063	0.0080	0.0075
Max	0.1000	0.1000	0.1000	0.1000
Min	0.0001	0.0001	0.0001	0.0001
Std Dev	0.0269	0.0262	0.0230	0.0216
n	26	26	23	23

Table 2.5-47 — Internal and External System Voltage and Angle Tolerances

From the summary statistics in the table above, we see there is a wide range in survey responses (from 0.0001 to 0.1). However, a review of the individual responses (not shown) reveals that the overwhelming majority of voltage magnitude and voltage angle convergence tolerances are under 0.01 kV per unit and 0.01 radians, respectively. These values essentially represent a “lowest common denominator.” The median responses are well under 0.01 kV per unit and 0.01 radians. Based on these observations, RTBPTF recommends that voltage magnitude and voltage angle convergence tolerances should be set to values no greater than the median values listed in Table 2.5-47. These are reasonable, achievable, and non-restrictive tolerances for most state estimator algorithms.

Operating Guidelines for State Estimator Solution-Quality Metrics

RTBPTF recommends that Operating Guidelines for state estimator solution-quality metrics be established that would apply until technically defensible metrics are developed. RCs need a high-quality estimation of the state of the bulk power system elements within their wide-area view to provide accurate data to other reliability analysis and market applications. Tools such as contingency analysis and power flow are highly dependent upon the state estimator's solution quality. For TOPs to maintain situational awareness of their "local" transmission systems, an accurate state estimator solution is required. An accurate solution is also necessary for other reliability analysis applications to determine the cause(s) of SOL violations. Table 2.5-3 details the applications that depend on the state estimator for the reliability coordinators and transmission operators. Table 2.5-48 lists the state estimator solution-quality metrics currently used by survey respondents.

What is Your Metric for Assessing the Accuracy of the Results of Your State Estimator Application? (Please check all that apply.)	**RC01**	**RC02**	**RC03**	**RC04**	**RC05**	**RC06**	**RC07**	**RC08**	**RC09**	**RC10**	**RC11**	**RC12**	**Other**	**Total**
Use cost index as a performance indicator	X	X	X	X			X				X	X	3	**10**
Use Chi-Squared criteria as performance indicator		X	X			X	X	X					3	**8**
Use measurement error/bias analysis as a performance indicator			X						X	X			4	**7**
Use average residual value as a performance indicator	X												1	**2**
Other(s)	X	X			X								3	**6**

Table 2.5-48 — State Estimator Solution-Quality (Accuracy) Metric

The quality of the state estimator solution should be measured using one or more of the metrics below; most of these recommended metrics are based on the survey results shown in Table 2.5-48 above. The reliability entity should track this set of metrics over time to gauge the pattern and determine what signals a problem with state estimator solution quality. Deviation from the "normal range" of these metrics should trigger state estimator maintenance and support. Even though no criteria for state estimator solution quality metrics are recommended at this time, these metrics are important because they could affect the contingency analysis solution.

The following metrics were not based on the survey results but rather on internal discussions within RTBPTF regarding recommending guidelines to the industry to assess state estimator solution quality.

1. *Cost Index*
   Cost index is also referred to as "Performance Index" or "Quadratic

Cost." In general, it measures the sum of the squares of the normalized estimate errors (residuals). Increasing cost index values could indicate deteriorating state estimator solution quality. See inset for a technical discussion.[57]

Technical Discussion of Cost Index

$$J(\hat{x}) = \sum_{j=1}^{m} \left[\frac{z_j - h_j(\hat{x})}{\sigma_j} \right]^2$$

where:

J is the "cost index" (sometimes called "performance index" or "quadratic cost")

m is the number of measurements being used in the estimate (excludes those that have been flagged bad and omitted)

z_j is the j^{th} measurement value (voltage, MW, Mvar, tap measurement, etc.)

$\hat{x}$ is a vector of estimated state variables (voltage magnitudes, voltage phase angles, etc.)

σ_j is the standard deviation of the metering error associated with measurement z_j (it is the inverse of the measurement weight)

$h_j(x)$ is a non-linear vector function that relates the state variable vector to measurement z_j.

The theoretical expected value of $J(\hat{x})$ is m-n where "m" is the number of measurements used in the estimate and "n" is the number of state variables. The theoretical variance of $J(\hat{x})$ is 2(m-n). Note that if the only state variables are voltage magnitudes and voltage phase angles, the value of n = 2b-1 where b is the number of electrical buses. The value of n will be greater if transformer taps and other quantities are used as state variables.

2. *Chi-squared Test*
   The Chi-squared test is a statistical test against the cost index to determine the presence of measurements that are inconsistent with estimated values; these could be bad measurements, topology errors, etc. This test is often used as a trigger for anomaly detection processing. Tracking the number of anomalous measurements could aid entities in tracking state estimator solution quality over time. Increasing numbers of anomalous measurements could indicate deteriorating state estimator solution quality. See inset for a technical discussion.[58]

[57] Grainger, John J., and William D. Stevenson, Jr. 1996. *Power System Analysis*. McGraw-Hill, Inc.
[58] Ibid.

Technical Discussion of Chi-Squared Test

If one assumes that all of the measurements used by the state estimator have errors that are independent of each other, follow a normal distribution, each having a mean of zero, then the cost index, $J(\hat{x})$, follows a chi-squared distribution with m-n degrees of freedom (where "m" is the number of measurements and "n" is the number of state variables). Under these conditions, the expected value of $J(\hat{x})$ is equal to m-n, and the expected value of its variance is equal to 2(m-n). Tabulated values of chi-square ($\chi^2_{m-n,a}$) associated with a given number of degrees freedom (k=m-n) and probability (α) are available in statistical tables or can be computed from formulas. If the computed value of $J(\hat{x})$, where $\hat{x}$ is a vector of estimated state variables, is less than or equal to $\chi^2_{m-n,a}$, there is a (1-α)*100% probability that there are no bad input measurements, or conversely, a α*100% probability that there is at least one or more bad input measurements. Therefore, if $J(\hat{x}) \leq \chi^2_{m-n,a}$ then the estimated state variables are considered "good". If $J(\hat{x}) > \chi^2_{m-n,a}$ then there is at least once bad measurement in the input and error processing must be done to locate and remove the bad measurement(s) from the inputs. A common procedure for eliminating bad measurements using the chi-square test is as follows:

1. Use the raw measurements $z_1, z_2, \ldots, z_m$ from the system to determine the least squares estimates of the state variables x, or $\hat{x}$.
2. Compute the estimated values of z, $\hat{z}$, from the estimated state variables using the relation $h(\hat{x})$.
3. Evaluate $J(\hat{x}) = \sum_{j=1}^{m} \left[\dfrac{z_j - h_j(\hat{x})}{\sigma_j} \right]^2$
4. For the appropriate number of degrees of freedom (m-n) and a user specified probability, α, determine whether or not $J(\hat{x}) \leq \chi^2_{m-n,a}$. If this is satisfied then the estimated state variables are accepted as being accurate and processing is done.

If $J(\hat{x}) > \chi^2_{m-n,a}$ then there is at least one suspect measurement in the measurement input. In this case use an algorithm)) to omit the "bad" measurements and then go back to step 1 above (i.e., remove the measurement(s) with the largest standardized error(s).

3. *Ranked Normalized Residual*s
   Normalized residuals are normalized individual estimate errors. Ranking normalized residuals in descending order aids entities in detecting causes of bad state estimator solutions based on specific measurements. Measurements that consistently rank high could indicate bad telemetry/measurement data.

4. *Maximum MW/Mvar Mismatch*
   The maximum MW/Mvar mismatch metric is applicable to state estimator algorithms that treat zero-injection buses (i.e., buses that do not have a load or generator connected to them) as high-confidence measurements. Macedo (2004)[59] says that state estimator MVA mismatch should be less than 10 MVA. Macedo does not distinguish between internal and external footprints; however, the survey results indicate some state estimators have the capability to track the maximum MW/Mvar mismatch on an internal and external basis. RTBPTF is not recommending specific values for internal/external MW/Mvar mismatch parameters. However, RTBPTF believes that where this capability exists, reliability entities should track both internal and external maximum MW/Mvar mismatch and observe trends over time. Sudden increases or an upward trend in maximum MW/Mvar mismatch could indicate deteriorating state estimator solution quality.

5. *Number of Iterations*
   Keeping track of the number of state estimator iterations over a period of time could provide information indicative of state estimator solution quality. The reliability entity should establish a normal range of state estimator iterations based on its model. If solution convergence exceeds these norms, state estimator results should be investigated.

6. *Major Topology Changes*
   Tools that keep track of major topology changes from one state estimator run to the other could help in tracing problems caused by changing topology of the network model.

[59] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

Factors Affecting State Estimator Solution-Quality Metrics

The values of the state estimator solution-quality metrics may depend upon many factors including:

1. **Modeling of electrical devices, connectivity, and mapping of telemetry data**. In state estimation, network topology is treated as given and assumed to be correct. If topology is incorrect, the state estimator may not converge or may yield grossly incorrect results. A topology error may stem either from:
   - Inaccurate status of breakers and switching devices, or
   - Errors in the network model.

   (Note that inaccuracies in the status of switching devices may be caused by a temporary or permanent loss of telemetry data)

2. **Availability and quality of telemetry data**. Telemetry data are essential components of the state-estimation process, as discussed extensively in Section 1.1,Telemetry Data, of this report.

3. **Inadequate Observability**. State estimation is extended to the unobservable parts of the network through the addition of pseudo-measurements. Pseudo-measurements are computed based on load prediction using load distribution factors, or they can represent non-telemetered generation assumed to operate at a base-case output level. The quality of pseudo-measurements may be questionable if they are not updated regularly to reflect current conditions. Note that when performing state estimation for the unobservable part of the network, it is possible to corrupt the states estimated from telemetry data.

4. **Measurement redundancy of the network**. This term is defined as the ratio of the number of measurements to the number of state variables in the observable area of the network.

Recommendation – A6

Identify minimum measurement observables, adequate redundancy, and critical measurements to improve state-estimator observability and solution quality.

Areas Requiring More Analysis

RTBPPTF recommends that the following areas be considered for further analysis. The Real-Time Tools Survey did not go in detail on these areas.

1. Minimum Measurement Observability
   The state estimator should be capable of monitoring the transmission network so that the estimator has sufficient measurements to calculate the voltage and angle at each bus. Without this minimum information, operators cannot know the real-time flows and expected post-contingency flows on the transmission system. Note that observability defines the percentage of the network meeting this minimum requirement. Current research and development in incorporating PMUs into the state estimator claims improved state estimator observability and solution quality.[60]

2. Inadequate Redundancy
   Redundant measurements are crucial for detecting and identifying bad data. Higher redundancy also ensures a more reliable state estimator solution in the face of a temporary loss of measurements. A bus measurement is observable if its state can be estimated using measured data without reliance upon pseudo-measurements, such as measurements from load or transformer tap models. Redundancy is a measure of the ability to maintain observability when access to telemetry data is lost. Critical measurements are those for which observability (in terms of the state estimator) will be lost if the measurement is lost. More investigation is needed for other appropriate measures such as the redundancy ratio (the total number of measurements divided by the total number of state variables) and the percent measurement of observable buses by kV level. The intent is to provide a state estimation driven by measurements as opposed to pseudo-measurements, which will minimize islands of poor measurement observability.

3. Critical Measurements
   The state estimator should be able to identify critical measurements in the system whose loss will result in either:
   - An inability to monitor a loading on a transmission element operated at high voltage and identified as critical to the system, or
   - An inability to monitor loading on a high-voltage autotransformer that is identified as critical to the system.

[60] See the following website:
http://www.pserc.wisc.edu/ecow/get/generalinf/presentati/psercsemin1/2psercsemin/abur_pmu_pserc_teleseminar_nov2005_slides.pdf#search=%22zero%20injection%20bus%20state%20estimator%22.

Recommendation – A7

Establish a pilot program to collect data and build appropriate state estimator performance metrics.

Additionally, RTBPTF recommends establishing a pilot program of a few RCs/TOPs that represent the individual systems, to collect data that could be used to establish the appropriate performance metrics. The pilot program would:

1. Review the recommended standards and devise a test plan.
2. Test the recommended standards for availability.
3. Recommend changes or additions to the recommended standards for availability.
4. Identify metrics for solution quality (accuracy) that have global applicability.
5. Test the identified metrics for solution quality.
6. Recommend standards (if possible) for state estimator solution quality.

Examples of Excellence

RTBPTF cites the unique approach taken by MISO to ensure that its state estimator provides the information necessary for operators to maintain situational awareness as an example of excellence (See EOE-8 in Appendix E).

Section 2.6
Contingency Analysis

Definition

Contingency analysis is a computer application used to analyze the impact on power system security of specific, simulated outages (lines, generators, or other equipment) or higher load, flow, or generation levels. Contingency analysis identifies problems such as line overloads or voltage violations that will occur if a new system event (contingency) takes place. The state estimator solution represents current system conditions and usually serves as the base case for contingency analysis. The information a contingency analysis generates enables RCs and TOPs to implement mitigation plans in advance of a contingent event such as a line trip. Contingency analysis is used as a real-time application as well as for studying potential scenarios. This section discusses both types of contingency analysis.

Background

The NERC Steering Group *Technical Analysis of the August 14, 2003 Blackout*[61] concludes that a nonfunctional contingency analysis was a key cause of the blackout:

> Cause 1e: FE did not have an effective contingency analysis capability cycling periodically on-line and did not have a practice of running contingency analysis manually as an effective alternative for identifying contingency limit violations. Real-time contingency analysis, cycling automatically every 5–15 minutes, would have alerted the FE operators to degraded system conditions….

NERC reliability standards IRO-005 and TOP-004 require all RCs and TOPs to monitor post-contingency conditions of bulk electric system elements. Most commonly, a real-time contingency analysis application is used to monitor potential post-contingency voltage and thermal violations.

NERC Reliability Standard TPL-002, System Performance Following Loss of a Single Bulk Electric System Element, is a planning standard. It requires that a transmission system be planned so it can be operated reliably following a Category-B contingency. As defined in this same standard, a Category-B contingency is an event that results in the loss of a single element of the bulk electric system, such as s generator, transformer, or transmission circuit, due to a single-line ground or 3-phase fault with normal clearing or the loss of an

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[61] Technical Analysis of the August 14, 2003, Blackout: *What Happened, Why, and What Did We Learn?* Report to the NERC Board of Trustees by the NERC Steering Group - July 13, 2004, page 96.

element without a fault. None of the operating standards, including the IRO and TOP series, contains an equivalent definition of a real-time contingency.

In a real-time operating environment, one or more elements are often out of service for maintenance or other reasons. Operators must be able to analyze and respond to any event that reasonably could cause the loss of an additional element, i.e., the next contingency. At a practical level, events that result in activation of protective relays are the most common causes of the next contingency. Consequently, real-time contingencies must be defined that accurately reproduce the results of activating protective relays, which are intended to remove elements from service to minimize damage or stop the spread of undesirable system conditions. Because more than one element is sometimes removed, it is insufficient to define a real-time contingency as a single element. A contingency must be defined as the set of circuit breakers or other automatic devices designed to clear a fault or otherwise respond to activation of protective relays that remove an element from service.

RTBPTF considers contingency analysis an essential tool for enabling operators to monitor and maintain the reliability of the bulk electric system. Macedo (2004)[62] states that real-time contingency analysis is a minimum requirement for network analysis tools for grid reliability and implies that operators should perform contingency analysis at least every 5 minutes on all facilities that operate at or above 100 kV within the RC area and on critical external facilities. RTBPTF agrees with Macedo's assessment that contingency analysis is a minimum requirement but does not agree that it must be performed every 5 minutes. In lieu of requiring a specific interval of execution, RTBPTF recommends requiring that contingency analysis solutions be produced within a reasonable interval in order to detect potential SOL/IROL violations. RTBPTF believes that the accuracy of contingency analysis solutions over time provides a quantifiable measure of the application's overall performance.

This Contingency Analysis section of the Real-Time Tools Survey examines the applications that RCs, TOPs, and BAs use to analyze the effects of contingent events. RTBPTF classifies real-time contingency analysis as a critical real-time tool.

Summary of Findings

All RCs and most other respondents to the contingency analysis section of the survey have a functional contingency analysis application, and most consider it an essential tool for system reliability. This section describes what respondents report about their contingency analysis applications, how they are integrated with other systems and alarms, and how the applications and their various features

[62] Macedo, Frank. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14. Available at: http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

are valued. Because RTBPTF finds contingency analysis to be an essential tool for monitoring the elements of the bulk electric system, RTBPTF recommends that all RCs and TOPs be required to have contingency analysis for their areas of operation and that reliability parameters be established for the applications. Survey results reveal the need to establish requirements for the quality of solutions derived from contingency analysis. Survey results also reveal the need to establish criteria for identifying which internal and external facilities should be included in the set of contingent elements to be analyzed.

Prevalence of Applications

All 17 RCs and approximately 54 percent of all other respondents (15 out of 28) have a functional contingency analysis application. Of the 13 respondents who have no such application, 8 plan to add one. Tables 2.6-1 and 2.6-2 summarize the reported prevalence of contingency analysis applications. RC responses are noted separately.

Do You Have Contingency Analysis?	RCs	Others	Total
Yes	17	15	**32**
No	0	13	**13**
Total	**17**	**28**	**45**

Table 2.6-1 — Prevalence of Contingency Analysis

Is Your Contingency Analysis Operational?	RCs	Others	Total
Yes	17	14	**31**
No	0	1	**1**
Total	**17**	**15**	**32**

Table 2.6-2 — Prevalence of Operational Applications

The 1 respondent who reports a non-operational contingency analysis application indicates there are plans to make it operational.

Perceived Value of Contingency Analysis Application

Most respondents perceive that contingency analysis is the most critical tool for secure system operation and is ”essential” for operating the system reliably after a disturbance. Table 2.6-3 summarizes the values respondents assign to contingency analysis.

How Valuable is Contingency Analysis?	RCs	Others	Total
Is contingency analysis essential?	16	13	**29**
Is contingency analysis desirable?	1	1	**2**
Is contingency analysis of minimal value?	0	0	**0**
Is contingency analysis of no value?	0	0	**0**
Total	**17**	**14**	**31**

Table 2.6-3 — Perceived Value of Contingency Analysis

Characteristics of Applications

Respondents were asked to describe the general characteristics of their contingency analysis applications. The questions in this section of the survey cover the integration of contingency analysis within EMSs, interfaces between contingency analysis and the state estimator, and algorithms used in the applications. Table 2.6-4 summarizes respondents' reported customization of contingency analysis applications. Table 2.6-5 describes the integration of contingency analysis with EMS systems. Table 2.6-6 describes the algorithms used in respondents' contingency analysis applications.

Degree of Contingency Analysis Customization	RCs	Others	Total
Off-the-shelf with some customization	9	6	**15**
Off-the-shelf	5	5	**10**
Highly customized	3	3	**6**
Total	**17**	**14**	**31**

Table 2.6-4 — Customization of Applications

Degree of Contingency Analysis Integration	RC	Other	Total
Fully integrated with production SCADA/EMS system	16	14	**30**
Interfaced to SCADA/EMS system	1	0	**1**
Stand-alone	0	0	**0**
Total	**17**	**14**	**31**

Table 2.6-5 — Integration of Contingency Analysis

Table 2.6-5 indicates that the contingency analysis applications of 97 percent of all respondents (30 out of 31) are integrated fully with their EMS systems. This result highlights the prevalence of contingency analysis as a real-time application.

Contingency Analysis Algorithm	RCs	Others	Total
Full AC	9	8	**17**
Decoupled	8	4	**12**
Other	0	2	**2**
Total	**17**	**14**	**31**

Table 2.6-6 — Contingency Analysis Algorithms

All respondents indicate that their contingency analysis uses the state estimator solution as a base case, which again implies the widespread use of contingency analysis as a real-time tool for predicting post-contingency system conditions.

Modeling Power Controls

Respondents were asked how their applications, when simulating contingencies, model power controls, both reactive (transformer taps, generators, and capacitors) and active (loads, generators, and phase shifters). Table 2.6-7 summarizes the modeling of internal load tap changer (LTC) taps during contingency analysis. Table 2.6-8 summarizes the modeling of shunt-series reactive devices during simulations.

Modeling LTC Taps in Contingency Analysis (Internal)	RCs	Others	Total
Locked globally	11	5	**16**
Can be moved for specific contingencies	1	4	**5**
Can be moved for specific LTCs	2	0	**2**
Globally free to move	1	3	**4**
Other(s)	2	2	**4**
Total	**17**	**14**	**31**

Table 2.6-7 — LTC Modeling in Contingency Analysis

Modeling Shunt/Series Reactive Devices in Contingency Analysis (Internal)	RC	Other	Total
Locked globally (reactive device status unchanged based on input)	9	6	**15**
Status can be switched in/out for specific contingencies	2	2	**4**
Status can be switched in/out for specific reactive devices	4	3	**7**
Globally free to change status switched in/out	1	2	**3**
Other(s)	1	0	**1**
Total	**17**	**14**	**31**

Table 2.6-8 — Modeling Shunt/Series Devices

Although no respondents report that they relax generator Mvar limits when modeling specific contingencies, 14 percent (4 out of 29) relax them for specific generators. Regarding active power controls, only 33 percent of respondents (10 out of 30) have applications that incorporate load change-over capability (the capability to transfer lost load to other specific loads). Seventy-three percent of respondents (22 out of 30), however, indicate that their applications can reallocate lost load and generation using generation participation factors. Tables 2.6-9 and 2.6-10 summarize capabilities related to active power control.

Do You Have Automatic Load Change-Over Capability?	RCs	Others	Total
Yes	6	4	**10**
No	10	10	**20**
Total	**16**	**14**	**30**

Table 2.6-9 — Automatic Load Change-Over Capability

Do You Reallocate Lost Generation and Load Using Generator Participation Factors?	RC	Other	Total
Yes	11	11	**22**
No	5	3	**8**
Total	**16**	**14**	**30**

Table 2.6-10 — Reallocation of Generation and Load

Most respondents (22 out of 30) reallocate lost generation and load using a single set of generation participation factors.

Actions Indicated by Applications

Respondents report that they model various remedial control actions in their contingency analysis applications. Most survey participants model LTCs, shunt reactive devices, and generators as remedial controls; however, 1 respondent uses RASs that require rigorous modeling. Table 2.6-11 summarizes the inclusion of post-contingency manual actions in contingency definitions. Table 2.6-12 summarizes the various remedial controls that respondents model.

Do You Consider Post-Contingency Manual Actions in Contingency Definitions?	RC	Other	Total
Yes	3	5	**8**
No	14	9	**23**
Total	**17**	**14**	**31**

Table 2.6-11 — Inclusion of Post-contingency Manual Actions

Controls Used for Remedial Action	RCs	Others	Total
Shunt reactive devices	9	3	**12**
Series reactive devices	3	1	**4**
Load tap changers	5	3	**8**
Phase shifters	2	1	**3**
Generator voltages	5	4	**9**
Under-voltage load shedding	2	2	**4**
Generation re-dispatch	4	4	**8**
Generation shedding	4	4	**8**
Bus and branch sectionalizing	3	1	**4**
Other(s)	1	0	**1**
No remedial action	5	4	**9**
Total	**16**	**10**	**26**

Table 2.6-12 — Remedial Controls in Contingency Analysis

Defining Contingencies

Contingencies can be defined based on the voltage levels of the elements involved. The minimum voltage level for elements included in contingency analysis usually depends on the structure of the region's transmission system. Survey respondents were asked what minimum voltage level they use in modeling contingencies. Fifty-three percent of all respondents (15 out of 28) monitor internal facilities having voltages less than 69 kV, and 82 percent (23 out of 28) monitor internal facilities having voltages less than 115 kV. These data indicate that most entities monitor lower-voltage facilities.

Responses indicate that RCs designate an average minimum voltage level of 105 kV although 1 RC models only those contingent elements that exceed 315 kV. Figure 2.6-1 shows the distribution of minimum kV levels of contingent elements that RCs and other respondents model.

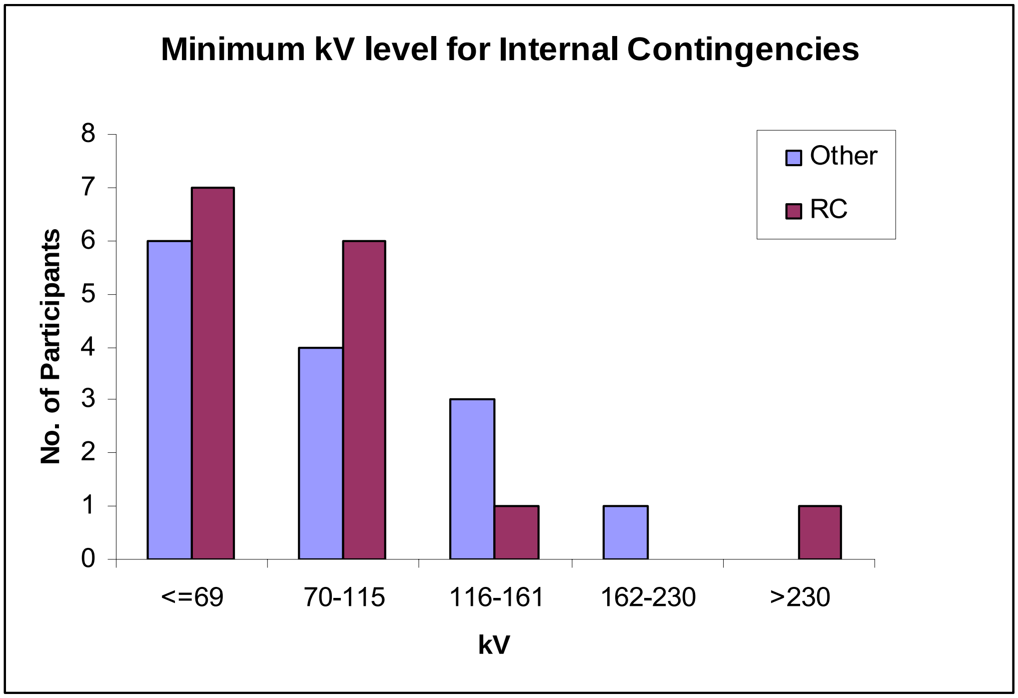

Figure 2.6-1 — Minimum kV Level for Modeled Contingencies

Figure 2.6-1 shows that 45 percent of respondents (13 out of 29) model contingencies that are less than 69 kV, and 35 percent (10 out of 29) model contingencies that have a minimum voltage between 70 and 115 kV. These data indicate that most entities consider the effects of outages of low-voltage transmission system elements although the practice varies greatly by region.

Seventy percent of all respondents (21 out of 30) define as contingencies all or most internal facilities that exceed the designated minimum kV levels. Only 23 percent of respondents (7 out of 30), however, define as contingencies all or most external facilities that affect internal systems. Table 2.6-13 summarizes reported practices regarding defining internal and external contingencies.

What Describes Your Contingency Definitions above Minimum kV Level?	RCs	Others	Total
All/most internal facilities are defined	10	11	**21**
Only select/critical internal facilities are defined	6	3	**9**
All/most external facilities that impact internal system are defined	7	0	**7**
Only select/critical external facilities that impact internal system are defined	4	9	**13**
No external contingencies are defined	5	5	**10**
Total	**16**	**14**	**30**

Table 2.6-13 — Contingency Definitions

An unexpectedly high 33 percent of respondents (10 out of 30) define no external contingencies. This result indicates a need to establish requirements for defining both external contingencies that affect internal systems and internal contingencies that could affect neighboring systems. This issue is addressed in the Recommendations for New Reliability Standards section below.

Survey responses define a range of transmission elements as contingencies. Exactly 60 percent of respondents (18 out of 30) categorize both circuit breakers and other transmission equipment as contingencies. Table 2.6-14 summarizes the elements respondents define as contingencies.

What Do You Define as Contingencies?	RC	Other	Total
Individual circuit breakers	9	10	**19**
Transmission lines	16	13	**29**
Transformers	16	12	**28**
Generating units	14	11	**25**
Bus faults	5	4	**9**
Phase-shifters (Phase angle regulators)	7	3	**10**
Loads	6	3	**9**
Shunt capacitors/reactors	5	1	**6**
Static var compensators	2	0	**2**
FACTS devices	0	0	**0**
DC lines (pole failures)	3	2	**5**
Multiple lines (on shared structure or right-of-way)	11	4	**15**
Other(s)	1	1	**2**
Total	**16**	**14**	**30**

Table 2.6-14 — Contingency Elements

Based on Table 2.6-14, contingencies most commonly comprise transmission lines and transformers. Individual circuit breakers also may be included in modeling contingencies, depending on the system configuration.

The total number of contingencies each respondent defines ranges from 30 to 10,000, as shown in Table 2.6-15. Figure 2.6-2 shows the ratio of total contingencies defined to the number of transmission lines and transformers each respondent models.[63]

Respondent	Total Contingencies	Respondent	Total Contingencies
R01	30	R17	900
R02	50	R18	973
R03	70	R19	1,000
R04	106	R20	1,000
R05	118	R21	1,500
R06	300	R22	1,500
R07	300	R23	1,800
R08	358	R24	3,000
R09	400	R25	3,500
R10	400	R26	4,340
R11	550	R27	10,000
R12	568	Average	1,324
R13	600	Median	800
R14	800	Minimum	30
R15	800	Maximum	10,000
R16	800		

Table 2.6-15 — Number of Contingencies Defined

63 Aliases are used for responses from RCs and TOPs to mask respondents' names. The aliases in this table are not necessarily consistent with those used in similar tables or figures in this report. That is, "R01" in any given table or figure is not the same as "R01" or the equivalent identifier in another table or figure in this report.

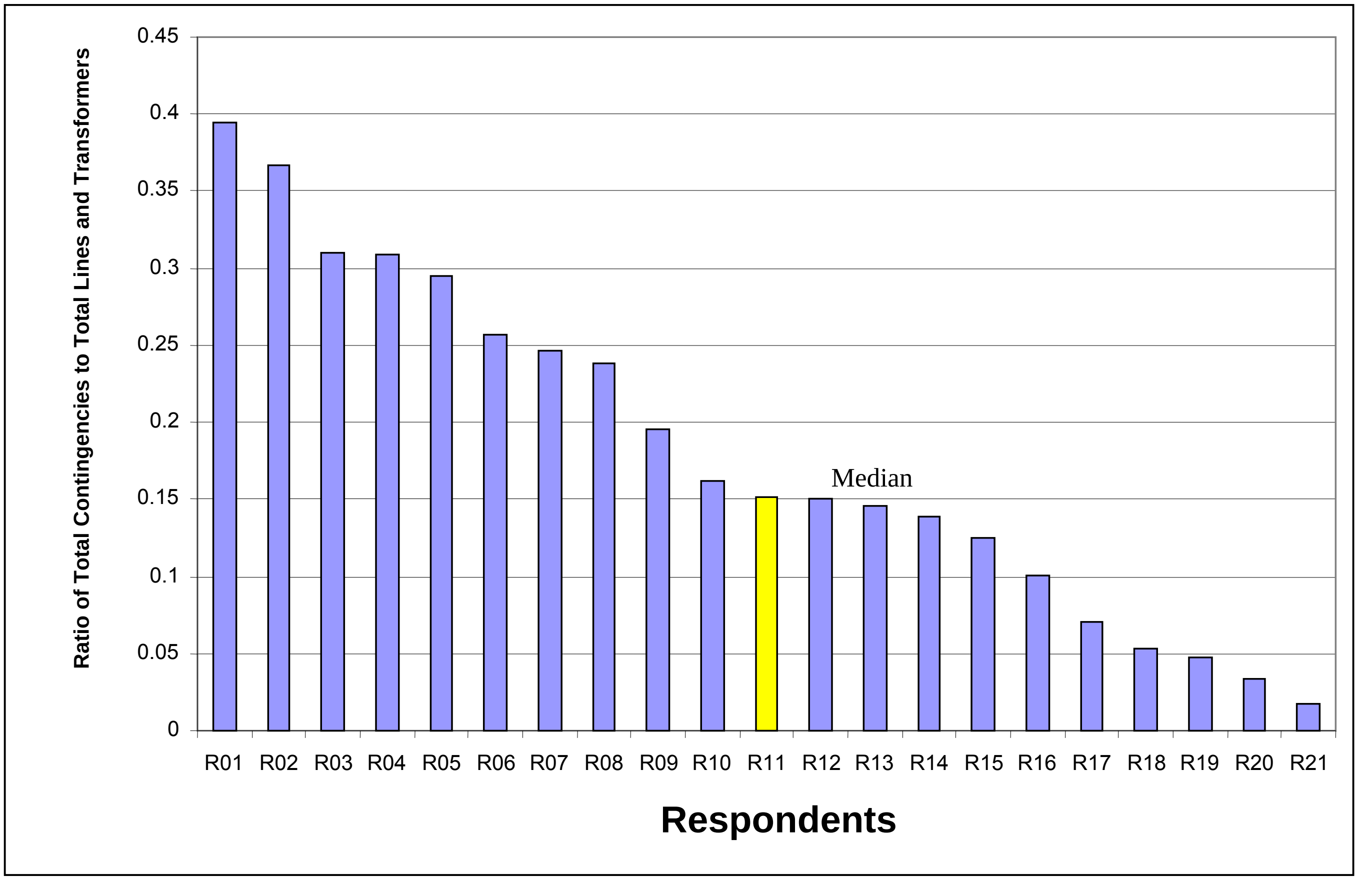

Figure 2.6-2 — Ratio of Total Contingencies to Total Branches and Transformers

Monitoring Limit Violations

The primary purpose of contingency analysis is to identify limit violations on monitored transmission system elements resulting from the post-contingency effects of the outages of transmission system elements modeled as contingent elements. Most RCs, TOPs, and BAs monitor selected elements, ignoring violations on any elements they do not monitor. Monitored elements are classified primarily by kV level. The minimum kV level for which internal system monitoring is applied is 24 kV. Figure 2.6-3 summarizes the minimum kV levels of transmission system elements that RCs and others monitor.

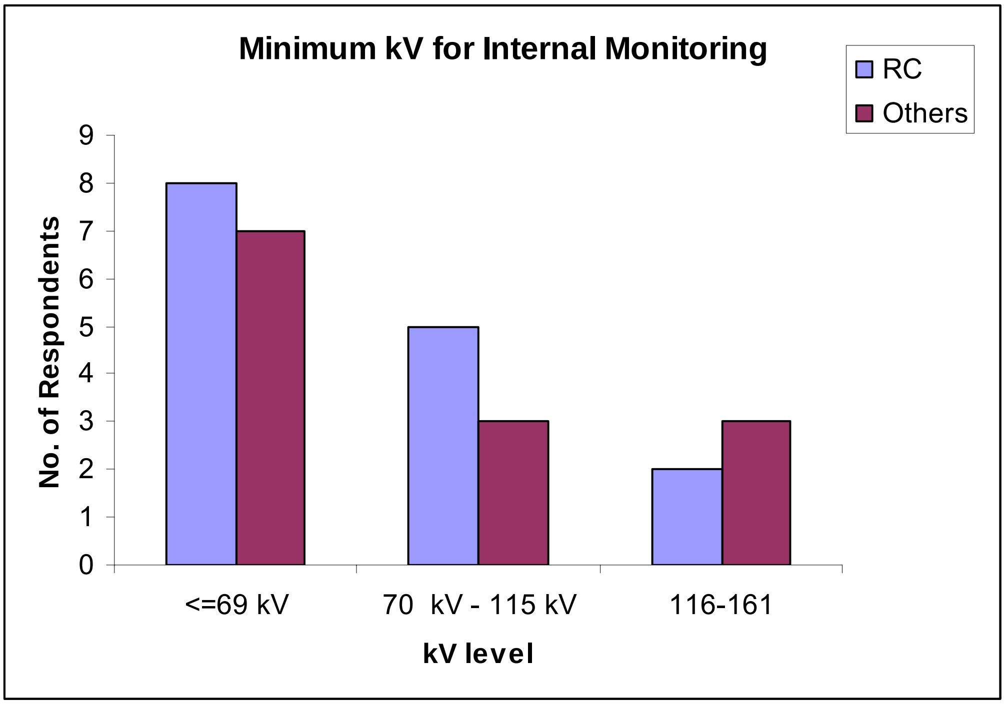

Figure 2.6.3 — Minimum kV Level Monitored

Figure 2.6-3 shows that 53 percent of all respondents (15 out of 28) monitor internal facilities having voltages less than 69 kV, and 82 percent (23 out of 28) monitor those having voltages less than 115 kV. These data indicate that most entities monitor lower-voltage facilities above their specified minimum kV level. However, few respondents also monitor all or most external facilities that affect their own system. Table 2.6-16 summarizes respondents' approaches to monitoring internal and external facilities.

What Best Describes Your Internal and External Monitored Facilities?	RCs	Others	Total
All/most internal facilities are monitored	13	11	**24**
Only selected/critical internal facilities are monitored	2	3	**5**
Total	14	15	**29**
All/most external facilities that impact internal system are monitored	7	0	**7**
Only selected/critical external facilities that impact internal system are monitored	6	8	**14**
No external facilities are monitored	3	6	**9**
Total	**16**	**14**	**30**

Table 2.6-16 — Internal and External Facilities Monitored

Only 23 percent of respondents (7 out of 30) monitor all relevant external facilities, and 30 percent (9 out of 30) monitor none. The data in Table 2.6-16 highlight the lack of wide-area monitoring.

As shown in Table 2.6-17, the total number of facilities each respondent monitors ranges from 35 to 10,000. The number of facilities monitored depends on the size of the network model used in the contingency analysis application.

Respondent	Total Monitored Facilities	Respondent	Total Monitored Facilities
R01	10,000	R13	750
R02	9,243	R14	500
R03	8,000	R15	500
R04	7,000	R16	487
R05	5,000	R17	254
R06	4,000	R18	212
R07	3,000	R19	118
R08	2,700	R20	35
R09	2,400	Average	2,946
R10	1,800	Median	1,675
R11	1,550	Minimum	35
R12	1,371	Maximum	10,000

Table 2.6-17 — Total Number of Facilities Monitored

Signaling Violations

Most respondents indicate that they can monitor thermal, low-voltage, and high-voltage violations; some (53 percent) can also monitor violations in bus voltage drop. Approximately 73 percent of all respondents employ some sort of alarm signal to alert them to contingency violations. Table 2.6-18 describes respondents' practices for signaling contingency violations.

Which Best Describes How You Alarm Violations?	RCs	Others	Total
General alarms — details viewed on contingency analysis displays	4	5	**9**
Detailed alarms — include details of facility, contingency, and violations	7	6	**13**
Others	1	0	**1**
No alarms — violations viewed on contingency analysis displays	4	3	**7**
Total	**16**	**14**	**30**

Table 2.6-18 — Signaling Contingency Violations

Contingency analysis applications typically can identify unsolved or diverged contingencies. Such contingencies are of special concern because they can indicate impending reliability problems. Sixty percent of respondents (18 out of 30) indicate that an alarm is used to signal unsolved contingencies. Only 38 percent (11 out of 29), however, state that their operators have tools or procedures to detect whether a failed contingency indicates a potential voltage collapse.

Contingency analysis also can warn operators of impending violations. Table 2.6-19 summarizes the methods respondents report using to warn operators of impending violations.

Which best Describes How Operators Are Notified of Approaching Violations?	RCs	Others	Total
Warning prior to actual violation level	10	10	**20**
No warning prior to actual violation level	5	3	**8**
Others	1	1	**2**
Total	**16**	**14**	**30**

Table 2.6-19 — Signaling Impending Violations

Approximately 70 percent of respondents (14 out of 20) indicate that operators can select the level at which an alarm will alert them of impending violations.

Application Features

Respondents were asked to describe the features of their contingency analysis applications. A key feature is how the application presents its results to system operators. Because there may be numerous defined contingencies (depending on system size), it is important that violations be categorized. Seventy-one percent of total respondents (22 out of 31) indicate that their application has a feature for categorizing violations, and all of them make use of this feature. Seventy-three percent of RCs (11 out of 15) and 68 percent of all respondents (15 out of 22) consider this feature "essential." Table 2.6-20 summarizes the criteria used to categorize violations.

What Criteria Could the Operator Use/Apply to Automatically Sort Violations?	RCs	Others	Total
Violations sorted by type	12	4	**16**
Violations sorted by severity	14	6	**20**
Violations sorted by ownership and/or geographic area	5	1	**6**
Violations sorted by contingency	7	3	**10**
As needed	1	1	**2**
Other(s)	3	1	**4**
Total	**16**	**6**	**22**

Table 2.6-20 — Criteria for Categorizing Violations

Survey respondents also were asked how violations are presented to operators. Tables 2.6-21 and 2.6-22 show the prevalence of color coding and/or graphical displays as techniques for visualization of violations.

Are Violations Color-Coded?	RCs	Others	Total
Yes	7	2	**9**
No	9	4	**13**
Total	**16**	**6**	**22**

Table 2.6-21 — Are Violations Color Coded?

Do You Have the Ability to View Graphical Displays to Determine Violation Severity?	RCs	Others	Total
Yes	8	1	**9**
No	8	5	**13**
Total	**16**	**6**	**22**

Table 2.6-22 — Can Violations Be Viewed Graphically?

Contingency analysis applications can be used to perform theoretical or study analyses of potential problems. The study analysis usually establishes a power-flow case representing anticipated future conditions (i.e., the time of today's forecasted peak load) and then performs "what-if" studies upon this base case (i.e., what if any defined contingency occurred during peak load conditions). All respondents report that their contingency analysis application has a study feature and that they use this feature. Table 2.6-23 summarizes respondents' perceived value of the study feature.

How do You Rank the Value of Study Contingency Analysis to Situational Awareness?	RCs	Others	Total
Essential	14	12	**26**
Desirable	3	2	**5**
Minimal	0	0	**0**
No value	0	0	**0**
Total	**17**	**14**	**31**

Table 2.6-23 — Perceived Value of Study Contingency Analysis

An important feature of contingency analysis applications is the ability to group and prioritize contingencies and monitored elements. This feature enables operators to easily enable/disable monitoring of sets of monitored elements and activate/deactivate sets of contingencies that have common features (i.e., that are at the same kV level) without having to control each one individually. Eighty-one percent of all respondents (25 out of 31) report having features that group and prioritize contingencies and monitored elements, and 45 percent (10 out of 22) consider those features "essential."

Respondents were asked whether their applications are able to identify the worst (most harmful) contingency impacting each monitored facility. Responses are presented in Table 2.6-24. Approximately half of all respondents consider this feature "essential."

Do You Have the Ability to Automatically Detect the Worst Contingency for Each Monitored Facility?	RCs	Others	Total
Yes	10	6	**16**
No	7	8	**15**
Total	**17**	**14**	**31**

Table 2.6-24 — Automatically Detecting the Worst Contingency

Some contingency analysis applications can calculate distribution factors (line outage distribution factors, generation shift factors, etc.) that can be used to identify remedial control actions such as re-configuration and re-dispatch or to trigger operating guides to help with resolving potential violations of operating limits. The contingency analysis applications of only 23 percent of respondents (7 out of 31) contain this feature.

Rate of Execution

Most respondents rely on periodic triggers to initiate a contingency analysis. The rate at which contingency analyses are executed ranges from once every minute to once every 30 minutes, with an average of once every 8 minutes reported by RCs and once every 13 minutes reported by TOPs. Figure 2.6-4 shows the rate at which RCs and others execute contingency analyses.

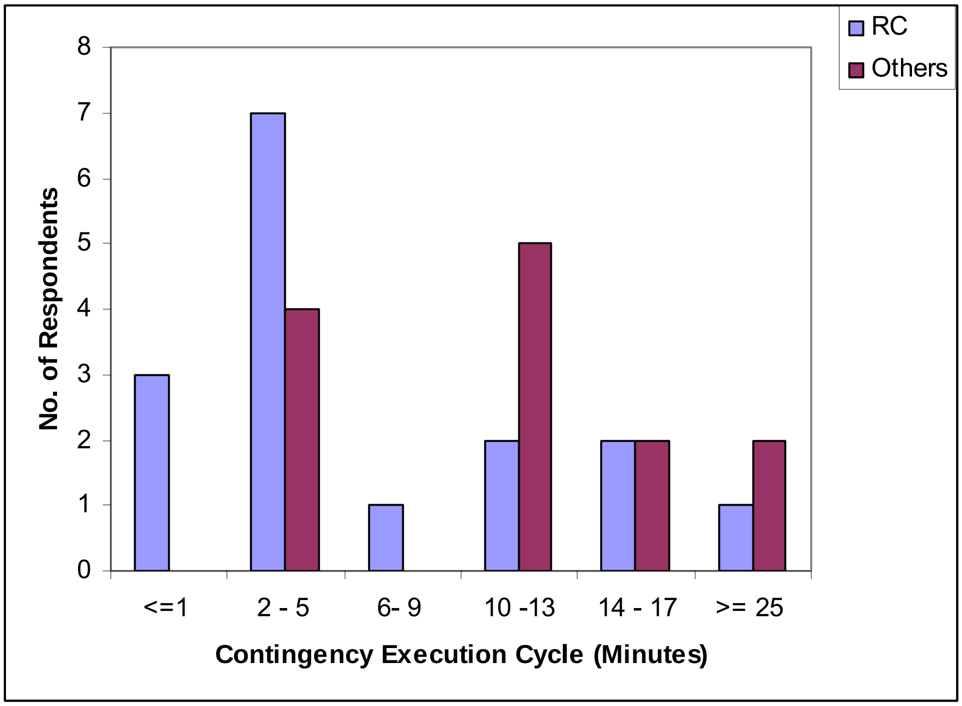

Figure 2.6-4 — Execution Rate for Contingency Analysis

The most common execution frequency is every 5 minutes. Some respondents use a manual trigger or disturbance triggers to augment routine periodic execution. The maximum time required for any RCs contingency analysis to execute is 4 minutes, with an average execution time of less than 1.5 minutes.

Availability of Contingency Analysis Application

The availability of the contingency analysis application is generally measured by how often it produces a successful solution for a given number of executions. Only 27 percent of respondents (8 out of 30) have historical data on contingency solutions or metrics for measuring their application's robustness. Table 2.6-25 summarizes the value respondents assign to being able to measure the availability of their contingency analysis applications.

How Would You Rank the Value of Having Capabilities in Contingency Analysis to Provide Availability Data?	RCs	Others	Total
Desirable	5	7	**12**
Minimal	5	3	**8**
None	1	1	**2**
Total	**11**	**11**	**22**

Table 2.6-25 — Perceived Value of Availability Data

A rather high 36 percent of respondents (8 out of 22) consider the ability to collect reliability data in contingency analysis to be of minimal value. In contrast, all who have tools to measure availability are using them. Respondents were asked approximately how often and how long their contingency analysis application is unavailable (the frequency distribution of down time). Of the 6 respondents who answered this question, most note that their answers rely on estimates rather than historical data. Five of those 6 respondents indicate that, of all the times that contingency analysis becomes unavailable, it is unavailable for less than 15 minutes for at least 95 percent of those times. Four of those respondents report that it is never unavailable for longer than 15 minutes.

Support for Applications

Because most respondents consider contingency analysis critical to real-time operation of their system, they understand the need to monitor the application's availability and functionality. Approximately 61 percent of respondents (19 out of 31) report having tools or procedures for monitoring the status of their contingency analysis application and making support personnel aware when it is unavailable or functioning incorrectly. Table 2.6-26 summarizes the availability of tools and procedures for monitoring the status of the contingency analysis application. Table 2.6-27 summarizes the perceived value of those tools and procedures.

Do You Have Tools or Procedures to Monitor the Status of Your Contingency Analysis?	RCs	Others	Total
Yes	12	7	**19**
No	5	7	**12**
Total	**17**	**14**	**31**

Table 2.6-26 —Tools/Procedures to Monitor Contingency Analysis Application's Status

How Would You Rank the Value of Having Tools to Monitor the Status of Your Contingency Analysis?	RCs	Others	Total
Desirable	4	7	**11**
Minimal	1	0	**1**
None	0	0	**0**
Total	**5**	**7**	**12**

Table 2.6-27 — Perceived Value of Monitoring Tools for Contingency Analysis Status

Approximately 94 percent of all respondents (17 out of 18), including all responding RCs, say that their contingency analysis is monitored continuously 24 hours per day, 365 days per year.

Recommendations for New Reliability Standards

The results of the Real-Time Tools Survey detailed in the previous section support the assertion of Macedo (2004)[64] that contingency analysis is a minimum requirement -- i.e., an essential tool for operators.

Recommendation – S1

Mandate the following reliability tools as mandatory monitoring and analysis tools

- Alarm Tools
- Telemetry Data Systems
- Network Topology Processor
- State Estimator
- Contingency Analysis

Contingency Analysis: Mandatory Monitoring and Analysis Tool

The survey results indicate that contingency analysis applications are inherently delivered as part of commercially available modern SCADA/EMS systems. RTBPTF considers contingency analysis an essential tool for enabling operators to monitor and maintain the reliability of the bulk electric system. Because contingency analysis is required for maintaining an "n-1" secure bulk power transmission system, RTBPTF places it in the Reliability Toolbox among the mandatory monitoring and analysis tools[65]. Existing NERC reliability standards implicitly assume the use of contingency analysis to aid RCs and TOPs in maintaining situational awareness for the bulk electricity system. Standard IRO-

[64] Macedo, Frank. 2004. *Reliability Software: Minimum requirements and Best practices*. FERC Technical Conference. July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps
[65] See the Reliability Toolbox Rationale and Recommendation section.

002 (Requirement R7) states "[e]ach Reliability Coordinator shall have ***adequate analysis tools*** [emphasis added] such as state estimation, ***pre and post-contingency analysis*** [emphasis added] capabilities (thermal, stability, and voltage), and wide area overview displays." Specifying that contingency analysis as part of the mandatory Reliability Toolbox clarifies that, under current NERC reliability standards, contingency analysis, as defined, is required. It also clarifies the term "adequate analysis tools."

Availability of Contingency Analysis Application

Given that contingency analysis is deemed a mandatory tool for maintaining situational awareness of the bulk electric system, it must be highly available and redundant. The availability of the contingency analysis application is discussed in the recommendations for Section 5.4, Critical Applications Monitoring. However, RTBPTF believes that a more complete understanding than that described in Section 5.4 is necessary. In particular, a metric for measuring adequate availability should be established.

Recommendation – S12

Specify and measure minimum availability for contingency analysis, including a requirement for solution quality.

RTBPTF Recommendation

RTBPTF developed the following proposed requirement (PR) for Standard TOP-006 in order to specify a minimum availability for contingency analysis.

PR1. Availability of Contingency Analysis

PR1.1 Real-Time Contingency Analysis Availability Metric 1 (RTCAA1): Each Reliability Coordinator and Transmission Operator shall ensure that its real-time Contingency Analysis produces at least one converged base-case solution and processes all defined contingencies for at least 97.5 percent of all10-minute clock periods (6 non-overlapping periods per hour) during each calendar month.

PR1.2 Real-Time Contingency Analysis Availability Metric 2 (RTCAA2): Each Reliability Coordinator and Transmission Operator shall also ensure that its real-time Contingency Analysis produces at least one converged base-case solution and processes all defined contingencies for every continuous 30-minute interval during a calendar day.

RTBPTF developed the following proposed measures (PMs) for the requirements given above. RTBPTF recommends that a pilot program (or field trial) be conducted to validate the effectiveness of the following PMs.

PM1. Measures for Availability of Contingency Analysis

PM1.1 Each Reliability Coordinator and Transmission Operator shall achieve, as a minimum, Requirement PR1.1 (RTCAA1) compliance of 97.5 percent. RTCAA1 is calculated by converting a Contingency Analysis availability ratio to a compliance percentage, as follows:

$$RTCAA1 = \left[1 - \frac{V_{month}}{TP_{month}}\right] * 100$$

$where:$

V_{month} = Violations per month

TP_{month} = Total Periods per month

The violations per month represent the number of 10-minute clock periods during which real-time Contingency Analysis did not produce at least one viable solution (one converged base-case solution and all defined contingencies processed).

PM1.2 Each Reliability Coordinator and Transmission Operator shall allow no RTCAA2 violations. One RTCAA2 violation equates to the real-time Contingency Analysis failing to produce at least one viable solution (one converged base-case solution and all defined contingencies processed) within any continuous 30-minute interval during a calendar day (three consecutive 10-minute clock periods). For example, if the real-time Contingency Analysis is unavailable continuously for 40 minutes (no viable solution within four consecutive 10-minute clock periods), RTCAA2 = 1 for the calendar day. If real-time contingency analysis is unavailable continuously for 60 minutes (no viable solution within six consecutive 10-minute clock periods), RTCAA2 = 2 for the calendar day. For simplicity, when the real-time Contingency Analysis is unavailable during a period that spans midnight, the RTCAA2 calculation shall be attributed to the preceding calendar day.

Rationale

Contingency analysis is a critical application for identifying potential IROL/SOL violations. Recommended requirement PR1.1 is consistent with the NERC mandate that MISO fully implement and test its state estimator and contingency analysis tools "to ensure they can operate reliably no less than every ten minutes."[66] Proposed requirement PR1.2 specifies that the real-time contingency analysis must be unavailable for no more than 30 minutes during a calendar day so that situational awareness is not compromised.

RTBPTF believes that these proposed availability requirements are consistent with requirements that operators remain aware of potential IROL/SOL violations and take the actions necessary to alleviate violations as soon as possible but always within 30 minutes. In addition, these recommended metrics are consistent, performance based, and, based on survey findings, technically feasible.

Quality of Solutions

Contingency analysis solves a single power-flow problem for each defined contingency. If the power-flow solution for a particular contingency fails to converge, it could mean that a reliability problem such as a voltage collapse might occur if the contingent event actually happened. In contrast, failure of a contingency to solve could indicate that a modeling error or other problem is degrading the quality of the base case and thus the results for all contingencies, even those that solve successfully. It is important to examine unsolved or diverged contingencies to assess whether the power-flow failure may indicate an impending problem. The survey indicates that 60 percent of all respondents consider failed contingencies important enough that audible alarms bring the failures to the operators' attention. RTBPTF shares this concern and believes that failed (unsolved) contingencies represent a key indicator of the quality of contingency analysis solutions.

RTBPTF Recommendations

RTBPTF developed the following proposed requirements (PRs) for Standard TOP-006 to ensure the quality of contingency analysis solutions.

PR2. Quality of Contingency Analysis Solutions

PR2.1 Each Reliability Coordinator and Transmission Operator shall have documented procedures for investigating and resolving the failure of a contingency to solve.

PR2.2 Each Reliability Coordinator and Transmission Operator shall have processes for recording (logging) all contingencies that fail

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[66] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 152.

to solve. Each log entry shall include a contingency identifier and the date/time of the solution failure.

PR2.3 Each Reliability Coordinator and Transmission Operator shall document the actions taken to resolve a failed contingency.

To validate the effectiveness of these requirements, RTBPTF proposes that they be included in the pilot program (or field trial) previously recommended for the availability metrics. RTBPTF developed the following proposed measures (PMs) for the requirements given directly above.

PM2. Measures for Quality of Contingency Analysis Solutions

PM2.1 Each Reliability Coordinator and Transmission Operator shall demonstrate that operators have ready access to current, approved procedures for investigating contingency failures.

PM2.2 Each Reliability Coordinator and Transmission Operator shall provide, if requested, hard copies of contingency failure logs for specified time periods.

PM2.3 Each Reliability Coordinator and Transmission Operator shall provide, if requested, records of the actions taken to resolve specified failed contingencies.

Rationale

Failure of a contingency to solve can indicate a poor-quality base-case solution or a problem with the system state such as a voltage collapse. In either case, situational awareness of potential IROL or SOL violations is compromised until personnel can identify and resolve the cause of the failed contingency. Enacted along with the recommended availability metrics, the above recommendations will provide that this critical real-time tool receives the attention and maintenance required to consistently produce solutions of sufficient quality for its intended purpose.

Criteria for Defining Contingency

The primary function of contingency analysis is to provide an early indication of an impending limit violation resulting from the outage of a transmission element. Thus, criteria are needed to identify which elements of the bulk electric system must be defined as contingencies. Requirement R1 of Standard IRO-003-1 states:

> Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as

> necessary to ensure that, ***at any time, regardless of prior planned or unplanned events*** [emphasis added], the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.

This requirement provides the criteria that define which facilities are to be monitored within the RC's area, but does not specify that RCs are to define all those facilities as contingencies. The emphasized words imply, however, that all possible contingent events must be analyzed in real time in order to maintain, under any possible topological configuration, the capability to identify potential IROL and SOL violations.

Real-time contingencies must be defined that accurately reproduce the results of activated protective relays, which are installed to remove elements from service to minimize damage or stop the spread of undesirable system conditions. Because in some cases more than one element may be removed, it is insufficient to define a real-time contingency as only a single element. A contingency must be defined as the set of circuit breakers or other automatic devices that operate to clear a fault or otherwise respond to protective relay actions intended to remove an element from service.[67]

Consider, for example, two transmission lines connected in a breaker-and-a-half scheme,[68] as shown in Figure 2.6-6. If the breaker between line B and bus 2 were open for maintenance, a fault on line A would trip the remaining two breakers, thereby removing both line A and B from service. If the contingency for the loss of line A was defined simply as the loss of line A, and not the tripping of the breakers connecting the line to the grid, then a real-time contingency analysis would not evaluate the true result of the event.

[67] RTBPTF is not recommending that contingencies be defined that represent relay mis-operations or over-trips.

[68] A breaker-and-a-half bus scheme is a "method of interconnecting several circuits and breakers in a switchyard so that three circuit breakers can provide dual switching to each of two circuits by having the circuits share one of the breakers, thus a breaker and one-half per circuit; this scheme provides reliability and operating flexibility." From the Bonneville Power Administration web site: http://www.bpa.gov/corporate/pubs/definitions/b.cfm - busscheme

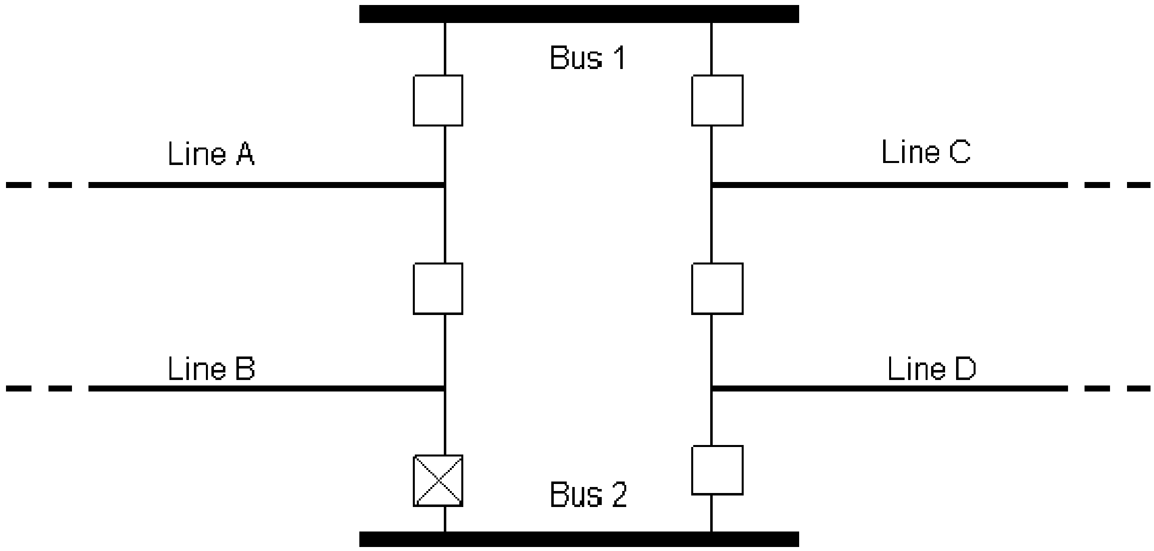

Figure 2.6-6 — Breaker-and-a-Half Scheme

Recommendation – S13

Specify criteria and develop measures for defining contingencies.

RTBPTF Recommendation

RTBPTF developed the following proposed requirements (PRs) for Standard TOP-006 to specify the criteria for defining contingencies that must be analyzed in real time.

PR3. Criteria for Defining Contingencies

PR3.1 Each Reliability Coordinator and Transmission Operator shall define as a contingency to be analyzed in real time each element of the Bulk Electric System[69] within its area of responsibility.

PR3.2 Each Reliability Coordinator and Transmission Operator shall define as contingencies to be analyzed in real time all critical Bulk Electric System elements in adjacent areas that, if taken out of service ***at any time, regardless of prior planned or unplanned events,*** could cause an IROL or SOL violation.

PR3.3 Each contingency must be defined to include the set of circuit breakers or other automatic devices designed to clear a fault or

[69] This recommendation assumes a rational and comprehensive definition of the bulk electric system. See the discussion of the bulk electric system in the Introduction of this report.

otherwise operate in response to activation of protective relays to remove the Bulk Electric System element from service.

RTBPTF developed the following proposed measures (PMs) for the requirements given directly above.

PM3. Measures for Defining Contingency

PM3.1 Each Reliability Coordinator and Transmission Operator shall have a list of the contingencies in its area of responsibility that are analyzed in real-time Contingency Analysis and shall document the criteria used to define as contingencies Bulk Electric System elements in its area of responsibility.

PM3.2 Each Reliability Coordinator and Transmission Operator shall have a list of contingencies in adjacent areas that are analyzed in real-time Contingency Analysis and shall document the criteria used to define as contingencies Bulk Electric System elements in adjacent areas.

PM3.3 Upon request, each Reliability Coordinator and Transmission Operator shall demonstrate for a randomly designated set of contingencies how the contingency definitions accurately simulate the results of a protective relay being activated.

Rationale

The recommended requirement that RCs and TOPs define as contingencies all bulk electric system elements in their areas of responsibility is based on RTBPTF's interpretation of requirement R1 of Standard IRO-003. If impact-based reliability criteria are used to identify bulk electric system elements, then by definition each of those elements potentially can impact reliability. If "bright-line" criteria such as voltage or MW levels are used to identify bulk electric system elements, such criteria are proxies for impact-based criteria, and the bulk electric system elements so identified also, by definition, have potential impacts on reliability. Either way, each bulk electric system element must be defined as a contingency, and the potential impact of each bulk electric system element must be analyzed in real-time contingency analysis.

As discussed above for the breaker-and-a-half scheme, contingencies must be defined in sufficient detail so that the most realistic scenarios are analyzed, thus providing operators with the most realistic system impacts. Events that activate protective relays are the most common causes of the next contingency. To assess the full effects of a contingency, the contingency definition must include the specific devices that operate in response to activation of the protective relay that removes a bulk electric system element from service.

Applicability Statement for Recommended Standards

RTBPTF recommends that all RCs and TOPs be required to have contingency analysis for monitoring all elements of their bulk electric system, as detailed in the recommended additions or modifications to NERC standards. Other responsible entities who use contingency analysis to support or complement their RCs' ability to operate the bulk electric system in accordance with formal agreements, contracts, or established practices shall be subject to the same standards for contingency analysis as their reliability coordinators.

Recommendation – G5

Identify only existing controls modeled in contingency analysis and develop conservative contingency screening criteria.

Recommendations for New Operating Guidelines

RTBPTF developed the following proposed operating guidelines to support the recommended requirements and measures presented above.

- RCs and TOPs should confirm that their contingency analysis models only the controls that exist in the field. For example, contingency analysis should not be configured to change the modeled tap positions of fixed tap transformers during the analysis in order to solve a contingency or eliminate limit violations. If a control is automatic (i.e., its activation does not require operator intervention), it can be modeled in contingency analysis. Manually activated controls either should not be modeled, or, if they are modeled, results should be presented both with and without the controls. The rationale for this guideline is that if a control must be manually activated, the operator must be notified of the potential contingency that requires activating that control.
- If contingencies are screened before inclusion in analysis, RCs should apply conservative screening criteria, so that potentially harmful contingencies are not misidentified as harmless.

Areas Requiring More Analysis

RTBPTF is not recommending additional areas for analysis related to Contingency Analysis.

Examples of Excellence

The transmission network (grid) is the power source for the offsite power system. The trip of a nuclear power plant itself can affect the grid and result in a loss of offsite power (LOOP). The most common occurrence is reduction in plant's switchyard voltage as a result of loss of the nuclear plant. The low voltage at the plant can activate the voltage-protection system and remove the plant safety bus from offsite power. A real-time contingency analysis application can be used to simulate such conditions and alert plant operators in advance.

In addition, a generic letter from Nuclear Regulatory Commission (NRC) recommends usage of real-time contingency analysis to determine the grid conditions that would make the Nuclear Power Plant offsite power system inoperable in the event of various contingencies.[70] During the August 14, 2003 northeast blackout nine nuclear power plants tripped and eight of these lost offsite power. The length of offsite power unavailability ranged from 1 hour to six and one-half hours. Although nuclear power plants are designed to cope with a LOOP event through the use of onsite power supplies, LOOP events are considered precursors to station blackout. An increase in the frequency or duration of LOOP events increases the probability of core damage.

RTBPTF cites the use of real-time contingency analysis by Entergy Corporation to accurately simulate the effects of loss of nuclear power plant on switchyard voltage as an example of excellence (See EOE-9 in Appendix E).

[70] Federal Register / Vol. 70, No. 69 / Tuesday, April 12, 2005 / Notices

Section 2.7
Critical Facility Loading Assessment

Definition

A critical facility loading assessment (CFLA) employs a computer application to evaluate a set of contingencies or other events that could affect reliability of the bulk electric system or one of its elements and then approximates the resultant post-contingency impacts for a pre-determined set of monitored elements. CFLA, which typically uses telemetered SCADA flows and line outage distribution factors (LODFs), represents an approximate, backup technique for obtaining a solution to contingency analysis if the primary state estimator and/or contingency analysis applications are unavailable.

Background

Macedo (2004)[71] cites use of CFLA as a best practice.

Summary of Findings

The CFLA section of the survey asks about use of CFLA applications for monitoring network conditions. Few Real-Time Tools Survey respondents report having a functional CFLA application. The applications that are in use appear to have wide ranges of capabilities and sophistication.

Of the 42 respondents to the CFLA question in the survey, only 4 RCs and 3 TOPs report having an application for performing CFLA. One RC gives no response. One RC that does not have CFLA ability plans to acquire the tool. Three TOPs also indicate they plan to acquire CFLA. Despite the low number of those who use CFLA, 6 out of the 7 respondents who have this application (all 4 RCs and 2 TOPs) rate it "essential" for situational awareness.

Features and Functions

Most of the respondents who report having CFLA use highly customized applications provided by their EMS vendors. Only 1 RC reports having developed an in-house CFLA application. All CFLA applications are either integrated or interfaced with the SCADA or the EMS; none operate in a stand-alone mode. Respondents' descriptions of their CFLA applications are presented in Table 2.7-1.

[71] Macedo, Frank. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14. Available at: http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

NOTE: In the columns of the following table, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, “6/7 = 86%” means that 6 out of a total of 7 respondents, or 86% of respondents, gave the indicated response.

Which Best Describes Your CFLA?	All	RCs
Highly customized	6/7 = 86%	3/4 = 75%
Off-the-shelf with some customization	1/7 = 14%	1/4 = 25%
Off-the-shelf	0/7 = 0%	0/4 = 0%
Supplied by SCADA/EMS vendor	3/7 = 43%	3/4 = 75%
Supplied by other vendor	0/7 = 0%	0/4 = 0%
Developed in-house	4/7 = 57%	1/4 = 25%
Fully integrated with SCADA/EMS system	6/7 = 86%	3/4 = 75%
Interfaced to SCADA/EMS system	1/7 = 14%	1/4 = 25%
Stand-alone	0/7 = 0%	0/4 = 0%
Triggered periodically	5/7 = 71%	2/4 = 50%

Table 2.7-1 — Descriptions of CFLA Applications

Among the 4 RCs who have CFLA, only 2 have applications that can define contingencies in true topographical terms of breakers and equipment. The other applications define contingencies in terms of equipment only. All CFLA applications can define branch contingencies, and 3 out of 4 can also define generator contingencies. One RC reports that its application also defines unit and other types of contingencies.

CFLA software packages differ significantly in terms of sophistication. Some use externally calculated LODFs and/or generator shift factors to distribute SCADA flows or injections from contingent branches or generators to monitored branches. Such applications contain no internal topology processor. The CFLA applications that incorporate topology processors can provide more accurate results. Some respondents claim their applications are capable of approximating true post-contingency apparent power (MVA) loading, but most approximate only the resultant real power (MW) loading.

The applications of all 4 reliability coordinators who have CFLA incorporate the same ratings from SCADA as the primary contingency analysis uses. Three of the CFLA applications can monitor branches or multiple branch sets. These 3 can, at a minimum, also define the critical internal and external facilities that affect loads on internal system facilities.

Three of the applications run by RCs contain either general or detailed alarms for alerting users to violations, which can be categorized by severity. All 4 reliability coordinators consider this feature either “desirable” or “essential.”

Users

Respondents report that the system operators and control room staff are the primary users of CFLA applications.

Performance, Monitoring, and Availability

The rates at which CFLA applications execute vary. One RC's application executes on a 1-minute cycle while another's executes on a 4-second cycle, and those of the other 2 execute in response to changes in SCADA status data. The application of 1 TOP executes every 10 minutes, that of another every 30 seconds, and the last every 4 seconds. One RC says the program runs "full-time"; another indicates that the results from CFLA trigger other programs.

Survey results reveal that no RC has developed a metric for CFLA availability. Only 1 RC indicates that such a metric would be desirable.

Support for Application

Only 2 RCs monitor the availability of their CFLA applications continuously and notify on-call or dedicated support staff of any application failures.

Recommendations for New Reliability Standards

Based on results from the very few who responded to this section of the survey, RTBPTF does not recommend creating or modifying reliability standards or operating guidelines to incorporate tools for performing critical facility loading assessment. RTBPTF, however, recommends performing additional analysis of CFLA and similar approximate techniques to assess their value in providing a contingency solution if contingency analysis and/or state estimator applications are unavailable

Recommendations for New Operating Guidelines

RTBPTF does not recommend the development of new operating guidelines for Critical Facility Loading Limits.

Recommendation – A8

Evaluate capability of critical facility loading assessment application in providing a backup solution if contingency analysis or the state estimator is unavailable.

Areas Requiring More Analysis

RTBPTF recommends that CFLA and similar approximate techniques be evaluated for their value for providing backup solutions in the event that the state estimator or conventional contingency analysis applications become unavailable. For CFLA to serve in this manner as a useful backup tool, the anomalies that can cause contingency analysis to fail should not be a cause for CFLA to fail as well. The capability of CFLA to enhance the wide-area view and assist in providing security of the bulk electric system should be analyzed further, and the capabilities that are crucial to making CFLA a valuable tool should be identified and communicated to software providers. Improvements should also be made to include breaker-oriented topology along with equipment outages in CFLA contingency definitions in order to improve the accuracy of the estimation.

Examples of Excellence

RTBPTF cites the use of a Thermal Tracking CFLA by PJM to screen for transfer interface violations and a number of potentially serious double-contingency violations as an example of excellence (See EOE-10 in Appendix E).

Section 2.8
Power Flow

Definition

Power flow is a computer application used to calculate the state of the electric power system based on load, generation, net interchange, and facility status data. Power flow calculates the system state in the form of flows, voltages, and angles. Power flows are available in both online and offline versions.

An application that evaluates online power flow is typically incorporated into an EMS (or has a direct data feed from an EMS) and utilizes node-breaker topology, whereas offline power flow utilizes models of bus branches and static data. This section of the report pertains only to online power flow, which hereafter is referred to simply as "power flow."

Background

EMSs utilize various applications to monitor and analyze the condition of a power system. Applications such as the state estimator and contingency analysis are intended to run automatically at given intervals to provide operators with real-time situational awareness. Applications such as power flow and study contingency analysis, on the other hand, are used to assess system conditions for the next hour or day. Power flow also is used in "n-1" contingency analysis to simulate the effect of the next worst contingency. In addition, it is used to identify potential voltage collapse or reliability problems.

The *NERC Blackout Report* identified inadequate hour-ahead and day-ahead studies. The following excerpts from the document emphasize the importance of look-ahead analysis.[72]

> FirstEnergy did not perform adequate hour-ahead operations planning studies after Eastlake 5 tripped off-line at 13:31 to ensure that FirstEnergy could maintain a 30-minute response capability for the next contingency. The FirstEnergy system was not within single contingency limits from 15:06 to16:06. In addition to day-ahead planning, the system should have been restudied after the forced outage of Eastlake 5.
>
> FirstEnergy did not perform adequate day-ahead operations planning studies to ensure that FirstEnergy had adequate resources to return the system to within contingency limits following the possible loss of their largest unit, Perry 1. After Eastlake 4 was forced out on August 13, the

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[72] North American Electric Reliability Corporation. 2004. *August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts.* February 10. p. 100.

operational plan was not modified for the possible loss of the largest generating unit, Perry 1.

The *NERC Blackout Report* implies that, if FirstEnergy had employed look-ahead studies using tools such as power flow, the cascading condition that caused the blackout of August 14, 2003, might have been avoided.

Summary of Findings

This section of the report examines how survey respondents, involved in operating transmission systems, operate, maintain, and utilize power-flow applications and discusses key issues faced by those who use power flow.

Power-flow applications, which are important for monitoring system reliability, appear to be used widely to simulate system conditions and to troubleshoot EMS problems. Routinely using them to perform look-ahead studies would further enhance operators' situational awareness.

The survey reveals a lack of systematic procedures for analyzing a failed power flow solution that could indicate potential voltage collapse. RTBPTF concludes that tools should be developed to warn operators of a failed solution or potential problems.

Prevalence and Perceived Value of Power Flow

There were 45 unique respondents to this section of the survey, including all 17 of the RCs surveyed. Table 2.8-1 shows that 71 percent of all respondents (32 out of 45) and 94 percent of reliability coordinators (16 out of 17) report having a power flow application. Most respondents (90 percent, or 28 out of 31) consider the application "essential" for situational awareness; a few (10 percent, 3 out of 31) consider it "desirable"; no respondents consider it to be of minimal or no value. Table 2.8-1 summarizes responses to general questions concerning power-flow applications.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, "32/38=84%" means that 32 out of a total of 38 respondents, or 84% out of respondents, gave the indicated response.

Question	All	RCs	Others
Do you have on-line power flow?	32/45=71%	16/17=94%	14/26=54%
If you do not have on-line power flow, do you plan to add it in the future?	7/13=54%	0/1=0%	7/12=58%
Is your on-line power flow operational?	31/32=97%	16/16=100%	13/14=93%
Do you rate your power flow "essential" as a reliability tool for situational awareness?	28/31=90%	13/16=81%	13/13=100%
Do you rate your power flow "desirable" as a reliability tool for situational awareness?	3/31=10%	3/16=19%	0/15=0%
Do you rate your power flow as of "minimal value" as a reliability tool for situational awareness?	0/31=0%	0/16=0%	0/15=0%
Do you rate your power flow as of "no value" as a reliability tool for situational awareness?	0/31=0%	0/16=0%	0/13=0%

Table 2.8-1 — Prevalence and Perceived Value of Power Flow

Application Interfaces and Features

Table 2.8-2 summarizes the characteristics of respondents' power-flow applications, and shows that all respondents report that their power-flow applications are integrated fully with their SCADA and EMS systems. In addition, EMS vendors appear to offer power flow as a standard product.

Power-Flow Application Characteristics	All	RCs	Others
Power flow fully integrated with production SCADA/EMS	30/30=100%	15/15=100%	13/13=100%
Power flow fully integrated with non-production SCADA/EMS	0/30=0%	0/15=0%	0/13=0%
Power flow supplied by SCADA/EMS vendor	30/31=97%	15/16=94%	13/13=100%
Power flow supplied by other vendor	1/31=3%	1/16=6%	0/13=0%
Power flow developed in-house	0/31=0%	0/16=0%	0/13=0%

Table 2.8-2 — Characteristics of Applications

Both operators and operations support staff use power flow applications. Eighty-one percent of all respondents (25 out of 31) report that operators or control room staff are the primary users of the applications; approximately 48 percent (15 out of 31) indicate that operations support staff also use the applications (see Table 2.8-3). These numbers indicate that power-flow applications are used widely as a tool to simulate system conditions and to troubleshoot EMS problems.

Users	All	RCs	Others
System operators and/or other control room staff	25/31=81%	12/16=75%	11/13=85%
Operations support staff	15/31=48%	7/16=44%	7/13=54%
Supervisory and/or management staff	4/31=13%	0/16=0%	4/15=27%

Table 2.8-3 — Primary Users

The survey also asked what applications are interfaced with power flow, and what is the source of the base case provided to initialize the power-flow application.

Table 2.8-4 summarizes the responses.

Application	All	RCs	Others
SCADA	17/31=55%	8/16=50%	9/15=60%
Alarm tools	6/31=19%	2/16=13%	4/15=27%
Monitoring and visualization techniques	18/31=58%	9/16=56%	9/15=60%
Network topology processor	15/31=48%	10/16=63%	5/15=33%
State estimator	28/31=90%	14/16=88%	14/15=93%
Contingency analysis	26/31=84%	14/16=88%	12/15=80%
Critical facility loading assessment	1/31=3%	1/16=6%	0/15=0%
Study real-time maintenance	7/31=23%	3/16=18%	4/15=27%
Study network topology processor	19/31=61%	10/16=63%	9/15=60%
Study contingency analysis	30/31=97%	16/16=100%	14/15=93%
Study critical facility loading assessment	1/31=3%	1/16=6%	0/15=0%

Table 2.8-4 — Applications Interfaced with Power Flow

Table 2.8-4 indicates that power-flow applications are interfaced primarily with the state estimator (90 percent, or 28 out of 31), contingency analysis (84 percent, or 26 out of 31), and study contingency analysis (97 percent, or 30 out of 31). Data from
Table 2.8-4 suggest that power-flow applications also are used frequently to provide a base case that is used in other applications, such as study contingency analysis or visualization techniques.

Table 2.8-5 and Table 2.8-6 summarize other characteristics of power-flow applications. Industry members most commonly use a full AC algorithm. The slack bus chosen varies evenly between single unit/bus or distributed generation slack. Full survey results for power flow are provided in Appendix D, which summarizes results not detailed in this Summary of Findings.

What Algorithm Does Your Power Flow Typically Use?	All	RCs	Others
Full AC	21/31=68%	12/16=75%	9/15=60%
Decoupled	9/31=29%	3/16=19%	6/15=40%
Other	1/31=3%	1/16=6%	0/15=0%

Table 2.8-5 — Power-Flow Algorithms

What Type of Slack Does Your Power Flow Typically Use?	All	RCs	Others
Single unit or load bus	15/31=48%	7/16=44%	8/15=53%
Distributed generation	12/31=39%	7/16=44%	5/15=33%
Distributed load	3/31=10%	1/16=6%	2/15=13%

Table 2.8-6 — Power-Flow Slack Bus

Although most respondents use their power-flow application to monitor the entire internal system for thermal and voltage violations, NERC reliability Principle 7 emphasizes the need for wide-area monitoring. As illustrated in Table 2.8-7, only 42 percent of respondents (13 out of 31) monitor selected external facilities that affect their internal systems, and 29 percent of respondents (9 out of 31) monitor no external facilities at all. Therefore, RTBPTF believes that standards for monitoring external facilities need to be developed. For more details, see Section 4.2, Modeling Practices and Tools.

External System Monitoring	All	RCs	Others
All/most external facilities impacting internal system are monitored	9/31=29%	7/16=44%	2/13=16%
Only select external facilities impacting internal system are monitored	13/31=42%	6/16=37%	6/13=46%
No external facilities are monitored	9/31=29%	3/16=19%	5/13=38%

Table 2.8-7 — External System Monitoring Using Power Flow

Verifying Accuracy

Survey results reveal that respondents use various methods to verify the accuracy of power-flow solutions. As illustrated in Table 2.8-8, for example, 61 percent (19 out of 31) of respondents use real-time applications (i.e., telemetry data system, alarm tools, state estimator, or contingency analysis) or other power-flow applications (i.e., offline power flow) to verify results of online power flow.

If a Power-Flow Solution is Questionable, How Do You Verify the Accuracy of the Solution?	All	RCs	Others
Compare results with distribution factors	4/31=13%	4/16=25%	0/13=0%
Compare results with another power-flow application	19/31=61%	9/16=56%	8/13=62%
Compare results with results from another case	17/31=55%	9/16=56%	6/13=46%
Compare results with another TOP's results	10/31=32%	6/16=38%	4/13=31%
Compare results with another study application's results	11/31=35%	7/16=44%	4/13=31%
Compare results with another real-time application's results	19/31=61%	12/16=75%	6/13=46%

Table 2.8-8 — Methods for Verifying Power-Flow Results

The importance of power-flow applications to reliability and the variety of methods used to verify results indicate a need to develop documented procedures for verifying the accuracy of results. The procedures should reflect the purpose for which the online power flow application is being used. For example, if power flow provides the base case for contingency analysis in a real-time system, results should be verified using real-time applications or SCADA.

A few respondents (20 percent, or 6 out of 30) indicate that they have tools/procedures to evaluate whether a non-converged power-flow solution indicates a possible voltage collapse. RCs (19 percent, or 3 out of 16) report a similar dearth of tools/procedures for identifying a potential voltage collapse indicated by a failed power-flow solution. Additionally, only 29 percent of all respondents (9 out of 31) report having procedures to detect and notify staff members of failed power-flow solutions. RTBPTF believes that tools should be developed to warn operators of a failed solution and indicate potential problems.

Power Flow in Look-Ahead Studies

Most respondents use power-flow applications to perform look-ahead studies. As shown in Table 2.8-9, eighty percent of all respondents report using power flow to perform hour-ahead to day-ahead analyses. Most users perform these studies on an as-needed basis, as shown in Table 2.8-10.

For Which Time Frames Do You Normally Perform Look-Ahead Power-Flow Studies?	All	RCs	Others
Look-ahead studies for less than 1 hour ahead	14/30=47%	7/16=44%	6/12=50%
Look-ahead studies from 1 hour to 1 day ahead	24/30=80%	11/16=69%	11/12=92%
Look-ahead studies for more than 1 day ahead	18/30=60%	7/16=44%	9/12=75%

Table 2.8-9 — Power Flow in Look-Ahead Studies

At What Periodicity Do You Normally Perform Look-Ahead Power-Flow Studies?	All	RCs	Others
Hourly	4/30=13%	4/16=25%	0/14=0%
Several times per day	5/30=17%	3/16=19%	2/14=14%
Daily	13/30=43%	6/16=38%	7/14=50%
As Needed	25/30=83%	11/16=69%	14/14=100%

Table 2.8-10 — Frequency of Look-Ahead Studies

Finally, the survey indicates that most respondents (46 out of 59) have a user interface to monitor power-flow data and results. Seventy percent of respondents (10 out of 13) who do not have an interface consider one "desirable."

Recommendations for New Reliability Standards

Given the need to support NERC reliability principles, and based on the inconsistencies identified in the Summary of Findings, RTBPTF recommends the following modifications to reliability standards.

Look-Ahead Analysis Requirement

Standard TOP-002 (Normal Operations Planning) and Standard IRO-004 (Reliability Coordination — Operations Planning) require reliability entities to perform day-ahead studies. Requirement R11 of TOP-002 states:

> [T]he Transmission Operator shall perform seasonal, next-day, and current-day bulk electric system studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these bulk electric system studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

The Purpose Statement for Standard IRO-004 says,

> [E]ach Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.

The requirement listed in IRO-004 and TOP-002 primarily focuses on day-ahead analysis and does not specify any requirements for hour-ahead analysis. To mitigate approaching SOL and IROL violations it is necessary to perform hour-ahead studies along with day-ahead and seasonal studies.

Recommendation – S14

Perform one-hour-ahead power-flow simulations to assess approaching SOL and IROL violations and corresponding measures.

RTBPTF Recommendation

To assess approaching SOL and IROL violations, RTBPTF recommends modifying TOP-002 and IRO-004 to include the following requirement:

> PR1: Each Reliability Coordinator and Transmission Operator shall, at a minimum, perform one-hour-ahead Power-Flow simulations during the following:
> - Occurrence of critical system event
> - Extreme load conditions
> - Large power transactions
> - Major planned outages

Fore the above requirement, RTBPTF recommends the following measure:

> PM1: Documented evidence showing results of hour-ahead studies and mitigation plans if needed must be kept by Reliability Coordinators and Transmission Operators.

Rationale

This recommendation addresses the following deficiency identified in the Blackout Report:

> FE did not perform adequate hour-ahead operations planning studies after Eastlake 5 tripped off-line at 13:31 to ensure that FE could maintain a 30-minute response capability for the next contingency. The FE system was not within single contingency limits from 15:06 to 16:06. In addition to day-ahead planning, the system should have been restudied after the forced outage of Eastlake 5.

The survey reveals that performing look-ahead studies is a prevailing practice. Forty-seven percent of all respondents perform look-ahead studies for less than 1 hour ahead, and 80 percent (24 out of 30 perform studies from 1 hour to 1 day ahead (see Table 2.8-9). An overwhelming 83 percent (25 out of 30) indicate that studies are done as needed (see Table 2.8-10).

The practice/process of performing look-ahead analysis during a major system event or when the power system is a stressed state suggests that reliability entities need to be more prepared. Systems are designed to withstand n-1 contingencies when they occur. However, changing conditions (e.g., scheduled system configuration, generation dispatch, interchange scheduling, and demand pattern changes) over the hour-ahead timeframe may need operator action in anticipation of these changing conditions. Performing look-ahead studies enhances operator situational awareness.

Recommendation – G6

Perform one-hour ahead contingency analysis to identify potential post-contingent problems approaching in next hour.

Recommendations for New Operating Guidelines

RTBPTF has recommended minimum standards for look-ahead analysis by listing events when one-hour-ahead analysis must be done. As an operating guideline and best practice, RTBPTF recommends performing a contingency analysis simulation using the one-hour-ahead power-flow base case every hour, employing an automatic method. This will identify potential post-contingent problems approaching in next hour.

Recommendation – A9

Verify accuracy of one-hour power-flow and contingency analysis results and ability to detect a potential voltage collapse revealed by a failed power-flow solution.

Areas Requiring More Analysis

RTBPTF identified the following two areas that require additional analysis:

Verification of Accuracy

The survey reveals that respondents use various methods to verify the accuracy of power-flow solutions. The methods and tolerances used in verifying results may depend on the purpose of the simulation. For example, an RC running power flow to simulate real-time conditions should verify the accuracy of results by comparing voltages, angles, and flows with those derived from state estimator. Because RTBPTF recognizes the need to further analyze and establish methods for verifying power-flow results, the task force recommends performing a detailed survey to identify current practices, which in turn could lead to developing standards or guidelines related to methods for verifying power-flow results.

Detection of Voltage Collapse

The survey reveals a lack of systematic procedures and tools for analyzing a failed power-flow solution that could indicate potential voltage collapse. RTBPTF suggests additional review and analysis of existing methods, tools, and algorithms for identifying a potential voltage collapse revealed by a failed power-flow solution.

Examples of Excellence

RTBPTF did not identify any Examples of Excellence related to Power Flow.

Section 2.9
Study Real-Time Maintenance

Definition
Study real-time maintenance (SRTM) is a study function that simulates real-time network applications (i.e. NTP, state estimator, contingency analysis etc.) and debugs problems without affecting the operation of the real-time applications. An SRTM tool can be an online application integrated with the production EMS system, an application integrated with a non-production EMS system [i.e. development, test, dispatcher training simulator (DTS) system etc.], or an offline application. (Note: Any reference to DTS is in the context of application maintenance, not training, which is not in RTBPTF's scope.)

Background

Given the complexity of the applications that make up EMS networks as well as their interaction with the telemetry, network model and actual power system, support staff must be able to quickly and easily recreate, debug, and resolve problems without affecting the real-time applications themselves. Without this capability, critical real-time network applications for monitoring and maintaining system reliability might be unavailable for extended periods.

Diminished situational awareness, attributable to the lack of availability of critical real-time network applications, contributed to the blackout of August 14, 2003. The causal analysis described in the *Outage Task Force Final Blackout Report*[73] reveals that the contingency analysis application in FE's control center was unavailable, and the state estimator and contingency analysis applications in the MISO control center were unavailable for some periods. Recommendation 37 in the *Outage Task Force Final Blackout Report* calls on entities to "[i]mprove IT forensic and diagnostic capabilities."[74] The report states that "[control areas] and [reliability coordinators] should seek to improve internal forensic and diagnostic capabilities, ensure that IT support personnel who support EMS automation systems are familiar with the systems' design and implementation, and make certain that IT support personnel who support EMS automation systems are trained in using appropriate tools for diagnostic and forensic analysis and remediation." RTBPTF believes that SRTM qualifies as a tool for performing diagnostic and forensic analysis and remediation of state estimator and contingency analysis applications, and that it is most effectively implemented independently, without hindering the real-time application it is analyzing.

Details in the *Outage Task Force Final Blackout Report* indicate that FE's contingency analysis application did not function properly and was not

[73] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. pp. 17–22
[74] Ibid. p. 166

maintained adequately. FE operators reported on-going problems with results from their real-time contingency analysis beginning when the application was installed in 1995. In addition, the application was not run in real-time mode. RTBPTF believes that if FE had adequate, trained, and experienced support staff who properly implemented their contingency analysis and routinely used an SRTM application to debug it and resolve problems, many of the causes of the August 14, 2003, blackout could have been avoided.

Based on details in the *Outage Task Force Final Blackout Report*, MISO support staff had a standard procedure for debugging real-time state estimator solutions by disabling the automatic triggers that normally would initiate real-time state estimator and contingency analysis. This practice resulted in periods when the applications were unnecessarily unavailable. Again, RTBPTF believes that if MISO had used an SRTM application to debug state estimator solutions, applications would have remained continuously available.

The SRTM section of the report summarizes reported use of and practices surrounding the SRTM (or equivalent) application.

Summary of Findings

This section of the report summarizes reported use of and practices surrounding the SRTM (or equivalent) application.

Real-Time Tools Survey results show that most RCs have, successfully use, and highly value SRTM. A total of 45 respondents answered the questions in the SRTM section of the survey. For respondents who perform multiple roles, each role is counted in the totals. Sixteen RCs responded, 25 TOPS responded uniquely (i.e., those that do not play any other role); and 2 balancing authorities (BAs) responded uniquely. Because so few BAs responded, the discussion in this section is based on results from RCs and TOPs only.

Prevalence and Perceived Value of SRTM

Table 2.9-1 summarizes responses to general questions about SRTM. Most RCs (88 percent) and 32 percent of those responding uniquely as TOPs indicate that their organizations have an SRTM tool. In addition, 95 percent of respondents with operational SRTMs consider the features “essential” or “desirable” for providing situational awareness.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, “32/38=84%” means that 32 of a total of 38 respondents, or 84% of respondents, gave the indicated response.

General Survey Questions	All	RCs	TOPs
Do you have SRTM?	22/45 = 49%	14/16 = 88%	8/25 = 32%
Is your SRTM operational?	21/22 = 95%	13/14 = 93%	8/8 = 100%
If it is not operational, do you plan to make your SRT) operational?	1/1 = 100%	1/1 = 100%	0/0 = NA
Do you rate your SRTM "essential" as a reliability tool for situational awareness?	11/21 = 52%	8/13 = 62%	3/8= 38%
Do you rate your SRTM "desirable" as a reliability tool for situational awareness?	9/21 = 43%	4/13 = 31%	5/8 = 63%
Do you rate your SRTM to be of "minimal value" as a reliability tool for situational awareness?	1/21 = 5%	1/13 = 8%	0/8 = 0%
Do you rate your SRTM to be of "no value" as a reliability tool for situational awareness?	0/21 = 0%	0/13 = 0%	0/8 = 0%

Table 2.9-1 — General Responses Regarding SRTM

Respondents' high opinion of SRTM is conveyed by comments such as the following:

> "This tool allows [us] to debug cases without affecting the Real Time System."
>
> "Sensational tool to debug real-time problems without affecting real-time applications."
>
> "Excellent feature to find the convergence problem in a network solution."

Characteristics of SRTM Applications

Most (86 percent) of respondents who have operational SRTM tools report that their SRTM is either off-the-shelf or customized somewhat. Most (81 percent) report having acquired their SRTM from their SCADA/EMS vendor. A preponderance (91 percent) report that their SRTM is fully integrated with either their production or non-production SCADA/EMS system (see Table 2.9-2). These results indicate that SRTM is a standard application offered by EMS vendors and is feasible to implement although most users perform some level of customization.

SRTM Characteristics	All	RCs	TOPs
Highly customized	3/21 = 14%	0/13 = 0%	3/8 = 38%
Off-the-shelf with some customization	12/21 = 57%	10/13 = 77%	2/8 = 25 %
Off-the-shelf	6/21 = 29%	3/13 = 23%	3/8 = 38%
Supplied by SCADA/EMS vendor	17/21 = 81%	11/13 = 85%	6/8 = 75%
Supplied by other vendor	2/21 = 10%	2/13 = 15%	0/8 = 0%
Developed in-house	2/21 = 10%	0/13 = 0%	2/8 = 25%
Fully integrated with production SCADA/EMS	18/21 = 86%	10/13 = 77%	8/8 = 100%
Fully integrated with non-production SCADA/EMS	1/21 = 5%	1/13 = 8%	0/8 = 0%
Interfaced to production SCADA/EMS	2/21 = 10%	2/13 = 15%	0/8 = 0%
Stand-alone	0/21 = 0%	0/13 = 0%	0/8 = 0%

Table 2.9.2 — Characteristics of SRTM

Most (62 percent) of RCs who have operational SRTM applications report that EMS/IT support staff are the primary users. TOP responses suggest that system operators and/or other control room staff, operations support staff, or EMS/IT support staff are all equal users (see Table 2.9-3). Note that each respondent could choose multiple primary users. Survey results indicate that it is primarily support staff, not system operators, who use SRTM, but a relatively high percentage of TOPs rely on system operators and/or other control room staff to use SRTM.

Primary SRTM Users	All	RCs	TOPs
System operators	8/21 = 38%	3/13 = 23%	5/8 = 63%
Operations support staff	11/21 = 52%	6/13 = 46%	5/8 = 63%
EMS/IT support staff	13/21 = 62%	8/13 = 62%	5/8 = 63%
Supervisory/Management	3/21 = 14%	0/13 = 0%	3/8 = 38%
Others	1/21 = 5%	0/13 = 0%	1/8 = 13%

Table 2.9-3 — Primary Users of SRTM

Most respondents that have an operational SRTM application report that it can simulate NTP, topology error detection, state estimator, and contingency analysis. Only a few report that they can simulate CFLA or other applications (see Table 2.9-4). Note that each respondent could choose multiple applications.

Applications	All	RCs	TOPs
Network topology processor	20/21 = 95%	12/13 = 92%	8/8 = 100%
Topology error detection	13/21 = 62%	7/13 = 54%	6/8 = 75%
State estimator	19/21 = 90%	12/13 = 92%	7/8 = 88%
Contingency analysis	19/21 = 90%	13/13 = 100%	6/8 = 75%
Critical facility loading assessment	1/21 = 5%	1/13 = 8%	0/8 = 0%
Others	3/21 = 14%	3/13 = 23%	0/8 = 0%

Table 2.9-4 — Real-Time Applications that SRTM Can Simulate

Recommendations for New Reliability Standards

Requirement R9 of NERC Standard IRO-002 mandates that RCs have plans and procedures for minimizing tool outages:

> [E]ach Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.

RTBPTF focuses on evaluating the capabilities of operators' critical real-time tools, not how those applications are maintained. RTBPTF believes that requirement R9 is sufficient to maintain the viability of analytical tools and does not recommend developing specific SRTM standards at this time.

Although the RTBPTF recommends no specific SRTM standards, SRTM capabilities should be considered when developing standards for maintaining and supporting other (critical) real-time applications that do require standards. Rather than requiring standards for SRTM, RTBPTF recommends establishing operating guidelines.

Recommendation – G7

Use the study real-time maintenance application to reproduce real-time snapshots.

Recommendations for New Operating Guidelines

Because survey results show that most RCs have, successfully use, and highly value SRTM, RTBPTF considers it appropriate to develop operating guidelines for this tool. The operating guidelines should help SRTM support the standards established for the critical real-time applications that do require standards (e.g., NTP, state estimator, and contingency analysis). SRTM supports the notion of "[i]mprove[d] IT forensic and diagnostic capabilities," as described in Recommendation 17 of the *Outage Task Force Final Blackout Report.* Users of real-time network applications may be able to improve their maintenance tools and practices based on achieving the capabilities recommended in the following operating guidelines for SRTM.

1. Whoever performs the RC, BA, or TOP function should be capable of using their SRTM application to simulate, at a minimum, the following real-time network applications:
    - NTP
    - state estimator
    - contingency analysis

2. If an entity implements its SRTM capability in a non-production environment, whoever performs the RC, BA, or TOP function should be capable of quickly and easily synchronizing that environment to the production environment (via network model, software, or user interface) so that real-time problems or snapshots can be reproduced.

3. Whoever performs the RC, BA, or TOP function should have the following SRTM capabilities:

- Ability to initiate the SRTM application from each of the critical real-time applications
- Ability to automatically save and archive real-time cases from various time periods
- Ability to automatically save and archive real-time aborted and non-converged cases
- Ability to initiate the SRTM application from an archive of historical real-time cases
- Ability, if requested, to save an SRTM case for future use
- Ability of SRTM to precisely duplicate real-time applications
- Ability to initiate study power flow and other study applications from a saved SRTM-analyzed case
- Possession of a distinct SRTM user interface

Recommendation – A10

Obtain additional information on how the study real-time maintenance application is utilized to enhance debugging capability.

Areas Requiring More Analysis

Before NERC establishes operating guidelines for SRTM and standards for maintaining and supporting critical real-time network applications, RTBPTF recommends obtaining additional details about how most industry members utilize SRTM capabilities. Based on a few survey comments, some respondents may believe that some of the capabilities of their study network application and DTS represent full SRTM capabilities. Although this idea is not necessarily incorrect, there are some subtle differences among these capabilities.

It may be impossible, for example, to recreate all real-time contingency analysis problems using study contingency analysis, because the base case for real-time contingency analysis may be the real-time state estimator solution whereas the base case for study contingency analysis may be a power-flow solution derived from the real-time state estimator solution.

It may be impossible to use DTS to recreate all problems in state estimator solutions because the state estimator in DTS may use measurements from the simulation rather than from real-time SCADA data.

If the full range of SRTM capabilities is accessible, network applications can be run and debugged exactly as they are, so that problems can be reproduced. If SRTM capabilities are implemented on a non-production, rather than production, EMS that system must be synchronized (regarding network model, software, and user interface) with the production EMS system to enable problems to be reproduced.

Examples of Excellence

RTBPTF cites as an example of excellence the use of an SRTM by PJM that includes a user interface that looks and feels exactly like the production network applications (See EOE-11 in Appendix E). SRTM allows PJM to quickly and easily recreate, debug, and resolve network applications problems without impacting the real-time network applications and use of this application has increased the overall availability of the real-time network applications.

Section 2.10
Voltage Stability Assessment

Definition

Voltage stability is defined as how much more load or transfer the system can sustain in a given direction before it encounters voltage instability. Voltage stability analysis (VSA) is an application that executes in near real-time and aids in the determination of system operating limits based on the voltage stability assessment using a recent snapshot of the real-time system. VSA may derive minimum voltages at key buses below which voltage collapse might occur if the system experiences additional stresses. It may also provide information on minimum dynamic reactive reserves required in local areas.

Note that this definition is not referring to offline voltage stability analysis tools that are usually used by engineering staff for medium-term or long-term studies. However, if such tools are used for studying near-real-time snapshots in answer to voltage stability questions by operators, they would be included in the VSA section of the Real-Time Tools Survey.

Summary of Findings

The VSA section of the Real-Time Tools Survey evaluates use of documented practices for monitoring voltage conditions. Survey responses indicate that although VSA applications are clearly useful, they apparently have not yet reached a stage of maturity that would render them a critical tool for reliable system operation.

VSA tools are used by a limited group of respondents. Only 6 out of the 14 reliability coordinators (RCs) (43 percent) and 6 out of the 24 transmission operators (TOPs) (25 percent) who responded to this section of the survey report having VSA capability. Just 5 RCs (36 percent) and 3 TOPs (13 percent) report having an operational VSA application. Interest in VSA may be growing, however, because 2 RCs and 5 TOPs plan to add a VSA package. In addition, 3 RCs and 6 TOPs plan to make their current application operational. The 5 RCs who have operational VSA applications deem the application ”essential” or “desirable” for monitoring system reliability. In addition, 2 out of 3 TOPs consider the application “desirable,” although one TOP considers it of “minimal” value.

Three RCs (of 5 responding) and 2 TOPs (of 3 responding) reported that their VSA applications can assess voltage stability (i.e., indicate pass/fail) for a set of contingency conditions. Some respondents indicated even though VSA is not widely used today, it could be of greater benefit if it was able to identify voltage stability margins and optimize the margin of voltage stability. The applications should be designed to display both the enhanced stability margin and a range of corrective actions. With further development, VSA applications have the potential to become another critical tool for monitoring system reliability in real time.

Users

Survey respondents identify operations planning staff, RCs, system operators, and control room staff as the primary users of VSA. Respondents who have operational VSA applications report that operations planning staff are the users (all 5 RCs and all 3 TOPs). Three RCs include control room operators as VSA users, while a few respondents identify EMS support staff, system planners, and “others” as users.

Functionality and Analytical Methods

Most VSA applications were developed in-house or by a third-party vendor other than the EMS vendor (reported by 4 out of 5 RCs and 2 out of 3 TOPs). Two out of 5 RCs (40 percent) and one out of 3 TOPs (33 percent) report that their application is highly customized. No RCs and only one TOP report using an off-the-shelf VSA product.

Four out of 5 RCs and both TOPs who responded report that their VSA applications are interfaced with state estimator solutions. VSA is most frequently interfaced with the real-time state estimator and contingency analysis applications although it was reported to be integrated with other applications such as unit commitment.

Three out of 5 RCs and 2 out of 3 TOPs report that they can assess voltage stability (i.e., determine pass/fail) for a set of contingency conditions derived from current system conditions. Three RCs and 2 TOPs consider this feature to be desirable or essential. Four out of 5 RCs report that their VSA application is used to evaluate fewer than 100 contingencies. While 1 respondent noted that it maintains a separate contingency list, 3 out of 5 RCs reporting indicated that the contingency list analyzed is derived from the EMS. Two of the 3 TOPs reporting also indicated the contingency list used is derived from the EMS.

The VSA application typically executes as a real-time tool. Three out of 5 RCs and all 3 TOPs who use the application report relying on a periodic trigger to execute VSA. Similar percentages use manual triggers. Respondents do not report using event or disturbance triggers. Frequency of execution ranges from once every minute to once every 60 minutes. The few RCs who responded to this section of the survey report that the application takes from 2 to 10 minutes (as measured by the wall clock) to execute.

Only 3 RCs and 2 TOPs responded to questions about the analytical methods that their VSA program employs to assess voltage stability. The applications of 3 RCs and both TOPs utilize Power/Voltage (PV) analysis. Other analytical methods include Reactive/Voltage (QV) analysis (0 RCs but both TOPs reporting they have the application); singularities in the Jacobian matrix (1 RC); power flow non-convergence (1 RC); and detailed time simulation (1 RC). Two respondents comment that they use other methods such as a ”continuation power flow” or ”model analysis” to assess the network’s voltage stability.

Two out of 5 RCs and 3 out of 4 TOPs state that their VSA applications calculate margins of voltage stability (see definition above). TOPs and RCs responded somewhat differently to the question of perceived value of this function as all 3 TOPs who have this feature say they use the ability to calculate voltage stability margins and consider it desirable. In contrast, although just 2 RCs report using a voltage stability margin application, both consider it essential. Three RCs and 1 TOP also indicated that they would consider the feature desirable if they had the ability to calculate voltage stability margins.

One out of 2 RCs reports that the application automatically assesses stability for increasing levels of load, and both RCs responding to the question indicate that their program automatically assesses stability for increasing levels of power transfer from an area (or set of areas) to another area. One of 3 TOPs responded that they use a load-increase-based method, and 1 of 3 TOPs responded that they use the increasing power transfer technique to assess voltage stability margins. Another TOP notes that they use a “direct analytical method” but does not describe the feature further.

The survey also asked whether respondents were incorporating advanced VSA tools to develop optimized margins of voltage stability. No RCs and only 1 out of 4 TOPs report having the capability to optimize or develop combinations of mitigation options to increase the system’s margin of voltage stability in near-real time for a set of contingency conditions with the ability to display both the enhanced stability margin and a set of corrective actions. Although only one entity reports using this feature, of respondents who lack the feature, all RCs (5) and TOPs (3) deem it desirable.

Three out of 5 RCs and 2 out of 4 TOPs report that their VSA applications have tools that display/visualize the level of voltage stability as an index of PV or QV curves or via tabular displays. Just 2 RCs and 2 TOPs report using the features although those same 4 respondents rate the feature “desirable” or “essential” (see Table 2.10-1).

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, “32/38=84%” means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

What Techniques Does the Program Use to Visualize the Voltage Stability of Your Power System Network?	All Respondents	RCs
Color-coded meters	1/4 = 25%	1/2 = 50%
Graphs of PV or QV curves	0/ 4 = 0%	0/2 = 0%
Other(s)	4/4 = 100%	2/2 = 100%
Spatial visualization of voltage stability margins by the boundaries	3/4 = 75%	2/2 = 100%
Tabular displays	0/4 -= 0%	0/2 = 0%
Voltage stability index	1/4 = 25%	1/2 = 50%

Table 2.10-1 — Techniques Used to Display Voltage Stability

One respondent comments that their application can generate SCADA alarms. Four RCs continuously monitor the availability of their VSA application, and 3 notify on-call or on-site support staff of application failures.

Recommendations for New Reliability Standards

RTBPTF is not recommending the development of new reliability standards related to VSA. Given the limited application of VSA within the industry, as indicated by the survey results summarized above, RTBPTF does not recommend developing new reliability standards for VSA applications.

Recommendations for New Operating Guidelines

RTBPTF is not recommending Operating Guidelines related to VSA. Given the limited application of VSA within the industry, as indicated by the survey results summarized above, RTBPTF does not recommend developing new operating guidelines for VSA applications.

Recommendation – A11

Assess the voltage stability assessment (VSA) application to learn how the VSA can be enhanced to become more widely used.

Areas Requiring More Analysis

RTBPTF believes that the industry would benefit from having NERC standards that support wide-area security of the bulk electric transmission system through real-time tools that assess voltage stability boundaries. A VSA tool could be used to generate the data required to determine this secure boundary and to identify appropriate corrective actions if needed. At present, VSA tools are used only by operations planners and by very few organizations. The survey did not determine whether the lack of wide use of this tool is attributable to the application being problematic, the results being unreliable, or the results failing to provide clear and actionable information. RTBPTF recommends that VSA capabilities be assessed further to learn why VSA tools are not used more widely, and how they could be enhanced to become more useful and more broadly used.

Examples of Excellence

RTBPTF cites the work of PJM to enhance its real-time VSA to provide control actions to avoid collapse and increase stability margins as an example of excellence (See EOE-12 in Appendix E).

Section 2.11
Dynamic Stability Assessment

Definition

Dynamic Stability Assessment (DSA) is an application (or a suite of applications) executing in near-real time that aids in the determination of stability-related system operating limits using a snapshot of the real-time system (i.e., current state estimator output). It may also provide an indication of dynamic stability margin for the most critical fault/contingency condition.

Note that this definition is not referring to offline stability analysis tools that are usually used by engineering staff for medium-term or long-term studies. However, if such tools are used for studying near-real-time snapshots to answer operators' voltage stability questions, these tools should be included in the DSA section of the Real-Time Tools Survey.

Summary of Findings

The DSA section of the Real-Time Tools Survey evaluates use of DSA applications for monitoring system conditions. Although DSA applications are useful, the responses to the DSA section of the Real-Time Tools Survey indicate that DSA applications are used very little; they apparently have not yet reached a stage of maturity that would render them a critical tool for reliable system operation.

Industry members appear interested in expanding the use of DSA, however. When the applications are further developed, they may have the potential to become another critical tool for monitoring system reliability in real time. As suggested by some of the survey responses, DSA applications would be enhanced if they were able to identify margins of dynamic stability and to optimize or search for combinations of mitigation options to increase the system's margin of stability.

As noted above, the applications apparently have not fully matured, but survey comments such as the following suggest that there is interest in developing DSA applications:

> Our Voltage/Transient Stability tools are not in production yet. We are in the early stages of implementing this tool as a real-time application for our reliability group. We feel that this is a desirable tool that will give the reliability folks another resource to maintain a safe and secure operational network.

It also appears that new installations and application enhancements are either in progress or planned for future implementation that could increase the value of this tool to that of an essential application. In the survey responses, 5 RCs and 5 TOPs state that they plan to add DSA to their suite of applications. This evidence suggests that industry members are interested in using DSA even though only 3 out of 16 RCs (19 percent) and 2 out of 23 TOPs (9 percent) report having a DSA application at this time, and just one RC (and no TOPs) state that their DSA application is operational. Respondents report that the primary users of DSA are operations planning staff and RCs. Results are displayed in various formats, such as a dynamic stability index or a tabular display, color-coded meters, color-coded bar graphs, and spatial visualization.

Based on survey results, DSA software packages are available from SCADA and/or EMS or other vendors. The applications can be applied off-the-shelf or with some customization. Just one TOP indicates that their application was developed in-house.

Functionality and Analytical Methods

Another indication that the application may not yet be mature is that respondents identified a variety of analytical methods for DSA applications, with no single method (or even two methods) emerging as dominant. The applications utilize various approaches, including time-domain simulation, energy function, equal-area criterion, and modal analysis. One RC states that its application utilizes “other direct analytical methods.”

Survey respondents report that a variety of periodic, manual, event or disturbance triggers are employed to start the DSA application.

Online DSA applications are being designed to evaluate dynamic stability not only for the given base conditions but also under various contingency conditions. The contingencies to be studied can be defined from the EMS or via a separate list. Survey results suggest that the applications can, and should, be designed to calculate dynamic stability margins when examining cases with increased loading or power-transfer levels. However, other evidence that the approach to this type of problem is not well established is that some systems estimate critical clearing times and others use energy function values to determine the instability point. Of interest was that 2 respondents report that their software is designed to optimize or search mitigation options to increase the system’s margin of stability in near-real time given a set of contingency conditions. This suggests that the results of DSA can serve an important role.

Recommendations for New Reliability Standards

Given the minimal use of DSA within the industry, as indicated in the survey results summarized above, RTBPTF is not recommending the development of new reliability standards related to DSA.

Recommendations for New Operating Guidelines
Given the minimal use of DSA within the industry, as indicated in the survey results summarized above, RTBPTF is not recommending Operating Guidelines related to Dynamic Stability Assessment.

Recommendation – A12

Assess the dynamic stability assessment (DSA) application to learn how the DSA can be enhanced to become more widely used.

Areas Requiring More Analysis

RTBPTF believes that the industry would benefit from having NERC standards that support wide-area security of the bulk electric system through real-time tools that could identify stability limits or boundaries which define areas of secure operation. Even though current DSA tools may not yet be mature, it appears that many in the industry believe that a DSA tool could be used to generate the data required to identify secure operating boundaries. Consequently, RTBPTF recommends that DSA be assessed further to learn how it currently operates and how it could be enhanced to become more useful, more valuable and more widely used.

Examples of Excellence

RTBPTF did not identify any Examples of Excellence related to DSA.

Section 2.12
Capacity Assessment

Definition

A capacity assessment is an evaluation of the planned and actual amount of power a system can generate. A capacity assessment gives system operators information about the location and availability of critical generating sources and identifies deficiencies in operating reserves. A capacity assessment always considers the real power (MW) that can be generated. When it also includes reactive power capacity (Mvar), it may also consider static devices, such as capacitor banks and reactors.

Background

Power system operators use various methods to monitor the generation resources available to meet power system demands that are changing throughout the day. Unit commitment plans and generation schedules usually are established in advance using one or more applications that prescribe ways to supply predicted system loads. Operators use processes and/or applications that monitor generating reserves on all or parts of the system to make sure capacity is adequate to meet credible generation contingencies and other deviations from the plan. These processes are discussed further in Section 3.1, Reserve Monitoring, of this report.

The applications that assess capacity in real time track both planned and actual generating schedules. These applications are designed to give operators a real-time view of all resources that could be called on if an unplanned event were to result in insufficient capacity in real time.

Tools for assessing capacity complement other wide-area tools and enhance situational awareness. Operators in areas subject to voltage difficulties benefit from increased situational awareness that includes a trustworthy assessment of available, unused real and reactive power capacities. As noted in Section 3.1, Reserve Monitoring, the balance resource and demand standards appear to clearly define real power (MW) operating reserves but not reactive power (Mvar) reserve requirements. Likewise, the calculation of reactive reserves is not well defined in that or any other NERC standard.

Summary of Findings

The capacity assessment section of the Real-Time Tools Survey examines operation, maintenance, and practices related to capacity assessment applications, as reported by those involved in operating transmission systems. This section also addresses the key issues faced by those who use capacity assessment applications.

Survey results reveal that applications for assessing capacity are widely used and generally regarded as important for maintaining awareness of system reliability. Capacity assessment applications, used primarily by control room staff, may incorporate various types of data but always utilize SCADA data. The applications typically receive no scheduled maintenance but are maintained when an alarm indicates the need.

Prevalence and Perceived Value of Applications

As illustrated in Table 2.8-1, 53 percent of all respondents and 69 percent of RCs state that they have a capacity assessment application. Most respondents who have such an application (64 percent) consider it “essential” for situational awareness. Another 28 percent find it “desirable” for situational awareness. Table 2.12-1 summarizes responses to general questions about capacity assessment applications.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, “23/43=53%” means that 23 out of a total of 43 respondents, or 53% of respondents, gave the indicated response.

Survey Question	All Respondents	RCs	Others
Do you have a capacity assessment (or equivalent) application?	23/43 = 53%	11/16 = 69%	12/27 = 44%
Is this application operational?	23/23 = 100%	11/11 = 100%	12/12 = 100%
If you do not have this application, do you plan to add it in the future?	2/19 = 11%	2/5 = 40%	4/24 = 17%
If planned or operational, do you consider it essential?	16/25 = 64%	10/13 = 77%	6/12 = 50%
If planned or operational, do you consider it desirable?	7/25 = 28%	3/13 = 23%	4/12 = 33%
Do you consider the application of minimal or no value?	2/25 = 8%	0/13 = 0%	2/12 = 17%

Table 2.12-1 — Prevalence and Perceived Value of Capacity Assessment Applications

Users of Applications

Capacity assessment applications are used or intended for use by operators and other support personnel (see Table 2.12-2). All respondents that have capacity assessment applications report that these applications are used primarily by operators or control room staff. Approximately 40 percent of all respondents indicate that their capacity assessment applications are also used by operations support staff. These survey results indicate that capacity assessment applications are used widely for monitoring system conditions and energy management issues.

Users	All Respondents	RCs	Others
System operators and/or other control room staff	25/25 = 100%	13/13 = 100%	12/12 = 100%
Management staff	8/25 = 32%	4/13 = 31%	4/12 = 33%
Support staff and others	10/25 = 40%	3/13 = 23%	7/12 = 58%

Table 2.12-2 — Users of Capacity Assessment Applications

Sources of Data for Applications

The survey asked respondents who report using capacity assessment applications what sources of data the application utilizes. All respondents report using SCADA data, but many also rely on manual entries and other sources that do not necessarily provide real-time data. Table 2.12-3 summarizes the responses.

Sources of Data	All Respondents	RCs	Others
SCADA	23/25 = 92%	12/13 = 93%	11/12 = 92%
Manual data	15/25 = 60%	8/13 = 63%	7/12 = 58%
IDC	0/25 = 0%	0/13 = 0%	0/12 = 0%
External applications	7/25 = 28%	6/13 = 46%	1/12 = 8%
Other	3/25 = 12%	3/13 = 23%	0/12 = 0%

Table 2.12-3 — Sources of Data for Capacity Assessment Applications

Three respondents note that “resource plans, load forecast,” and “other data” (typically derived from market data) provide input to capacity assessments.

Approximately 59 percent of all respondents and all RC respondents report they can monitor reactive power capacity (Mvar) as well as real power capacity (MW). Only 12 percent of all respondents indicate that they monitor other types of capacity. Two users note that they monitor the effects of reserves on the ability of critical interfaces to withstand select double-contingencies. These latter responses indicate that some respondents confuse the notion of the various types of capacity (MW, Mvar, other) with how capacity is evaluated (base case, contingency, etc.). The survey questions may not have highlighted this distinction adequately.

Support for Applications

Capacity assessment applications generally do not receive routine attention from support personnel. About 62 percent of all users (57 percent of RCs and 64 percent of TOPs) note that they report any application failures to support personnel. A majority (63 percent) report that support is not automatic or scheduled. Instead, operators call support if an alarm indicates that the application is not functioning. Few (21 percent overall and only 13 percent of RCs) maintain the applications on a regular (weekly) basis rather than an as-needed basis.

Recommendations for New Reliability Standards

Section 3.1, Reserve Monitoring, presents RTBPTF's recommendations for new standards related to operating reserves referenced in this section. Specifically, RTBPTF recommends that requirements be added to existing standards so that operators will monitor critical components of real power operating capacities that affect these reserve quantities.

Recommendations for New Operating Guidelines

RTBPTF is not recommending operating guidelines related to capacity assessment.

Recommendation – A13

Analyze the need to define reactive power (Mvar) capacity requirement and use a Mvar assessment application.

Areas Requiring More Analysis

RTBPTF recommends further analysis of applications that provide comprehensive capacity assessments. This analysis should be coordinated with analysis of tools used to evaluate operating and capacity reserves in Section 3.1, Reserve Monitoring.

Because of the shortcoming noted above, that the current BAL standards do not define reactive power requirements, RTBPTF identified reactive reserve requirements as a major issue; this is discussed in detail in the Introduction to this report. Specifically, RTBPTF believes that mandatory requirements for real-time tools for reactive reserve monitoring would be highly desirable; however, before such recommendations can be formulated, NERC must define technically justified and feasible-to-implement requirements for determining the appropriate amount and location of acceptable reactive reserves and clarifying how reliability coordinators should monitor these reserves.

Examples of Excellence

RTBPTF did not identify any Examples of Excellence related to capacity assessment.

Section 2.13
Emergency Tools

Definition

Emergency tools are applications or procedures that operators use when the power system enters or is about to enter an emergency.[75]

Background

Maintaining the reliability of a power-generating or transmitting facility is a complex enterprise that requires trained and skilled operators, sophisticated computers and communications, and careful planning and design. NERC has developed standards for operating and planning electric systems to safeguard the reliability of transmission grids. The standards are based on seven key concepts that are identified in the *Outage Task Force Final Blackout Report*.[76]

1. Continuously balance power generation and demand.
2. Balance reactive power supply and demand to maintain scheduled voltages.
3. Monitor flows over transmission lines and related facilities so as to stay within thermal (heating) limits.
4. Keep the system in a stable condition.
5. Operate the system so that it remains reliable even if a contingency occurs, such as the loss of a key generator or transmission facility (the "n-1 criterion").
6. Plan, design, and maintain the system to operate reliably.
7. Prepare for emergencies.

The *Outage Task Force Final Blackout Report* further states:

> System operators are required to take the steps to plan and operate a reliable power system, but emergencies can still occur because of external factors such as severe weather, operator error, or equipment failures that exceed planning, design, or operating criteria. For these rare events, the operating entity is required to have emergency procedures covering a credible range of emergency scenarios.[77]

Current NERC standards assign RCs the authority to direct TOPs and BAs to shed load, and TOPs and BAs are required to comply with those directives. No

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[75] The NERC Glossary defines "emergency" as "[a]ny abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System."
[76] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. pp. 6–7.
[77] Ibid. p. 10.

standards, however, mandate RCs to maintain situational awareness of their own capability to shed load under real-time operating situations.

Tools/applications for use during a range of credible emergency conditions or scenarios are essential to maintain reliability of the bulk electric system. The Real-Time Tools Survey examined the following types of emergency tools:

- Residential Load or Demand-Side Management – This type of tool enables operators to curtail residential electricity demand[78] for specific appliances. Residential load or demand-side management (DSM) tools consist of the planning, implementing, and monitoring activities that are designed to encourage residential consumers to modify their level and pattern of electricity usage. These activities are also designed to allow shaping of electricity demand through direct computer control of specific appliances. For example, when necessary, operators could turn off air-conditioners of residential customers that sign up for a residential DSM program to reduce electricity demand.

- Commercial/Industrial Load or Demand-Side Management – This type of tool enables operators to curtail commercial/industrial electricity demand. This type of tool is similar to residential Load or DSM but is applied to commercial/industrial customers. A typical application of this type of tool is demand reduction in which operators use direct computer control to disconnect the electric supply feed from the supplying entity.

- Load Reduction by Voltage Reduction – This type of tool enables operators to curtail electricity demand by reducing distribution-level voltages. This scheme usually involves direct computer control (via SCADA systems) to automatic voltage regulating relays on LTC power transformers and step voltage regulators. Controlling the dry contact closure to the regulating relay boosts the sensed voltage of the voltage regulating relay and thus reduces its center band voltage to a lower level.[79] This causes a reduction of the distribution voltage schedule, which reduces electricity demand for a short period.

- Rotating Load Shed – This type of tool enables operators to curtail load by initiating or scheduling load shedding. The *Outage Task Force Final Blackout Report* defines “load shedding” as “… the process of deliberately removing (either manually or automatically) pre-selected customer demand from a power system in response to an abnormal condition, to maintain the integrity of the system and minimize overall customer

[78] The NERC Glossary defines “demand” as “[t]he rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time” or “[t]he rate at which energy is being used by the customer.”
[79] http://www.beckwithelectric.com/infoctr/appnotes/App16.pdf

outages."[80] For this type of tool, rotating load shed refers only to manual load shedding scheduled or initiated by operators via computer control.

Although not all personnel have direct control over all of the emergency tools discussed in the Real-Time Tools Survey (i.e., most RCs do not have direct control over load-shedding applications), if RCs has the tools to monitor the status of emergency tools under their purview, this would enhance situational awareness for both TOPs and RCs. Results form the Emergency Tools section of this report go hand-in-hand with the findings reported in Section 3.5, Load Shed Capability, of this report.

Summary of Findings

The primary finding of the emergency tools section of the Real-Time Tools Survey is that certain types of emergency tools are not widely available, nor are they widely used throughout the industry. The most commonly used emergency tool is rotating load shed, as reported by a small number of respondents. Although few respondents have the emergency tools described in this section, they are nonetheless required to be aware of the situations monitored or controlled by the tools.

Prevalence of Emergency Tools

Table 2.13-1 summarizes the responses to the survey section regarding access to emergency tools. Only 46 percent of respondents to this section of the survey (19 out of 41) indicate that they have emergency tools. This result is surprising given that current NERC reliability standards implicitly require an accessible and functional operator-controlled load-shedding capability (through a tool/application such as rotating load shed). Requirement R2 of Standard EOP-001, for example, states that:

> [T]he Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

In addition, the purpose of Standard EOP-003 is described as: "[a] Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection." Requirement R8 of EOP-003 states, "[E]ach Transmission Operator or Balancing Authority shall

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[80] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 216.

have plans for Operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency." All of these requirements imply the necessity for operator-controllable, emergency tools for shedding load.

The low percentage of respondents who report having emergency tools is inconsistent with the findings described in Section 3.5, Load-Shed Capability. In that section of the survey, 74 percent (34 out of 46) of respondents report having some sort of documented practices for maintaining situational awareness of load-shed capability. In short, in the emergency tools section of the survey, 46 percent of respondents indicate they have emergency tools, but in the load-shed section of the survey, 74 percent indicate they have documented practices for maintaining awareness of load-shed capability. This inconsistency may mean that some respondents who report having documented practices for load-shed capability do not use an operator-controlled emergency tool. Instead, these entities may depend entirely on automatic field equipment [i.e., under-frequency load shed (UFLS) or under-voltage load shed (UVLS) relays] to provide load-shed capability.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, "32/38=84%" means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

Respondents	Do You Have Emergency Tools, such as Residential Demand-Side Management or Rotating Load Shed?
All	19/41 = 46%
RCs	5/14 = 36%
Others	14/27 = 52%

Table 2.13-1 — Prevalence of Emergency Tools

Perceived Value of Emergency Tools

The survey asked respondents to rate any operational emergency tools that they have available in terms of their situational awareness value. Table 2.13-2 summarizes the responses.

Respondents	How do You Rate Your Emergency Tools as a Reliability Tool for Situational Awareness?	
	Application is “essential”	Application is “desirable”
All	11/18 = 61%	7/18 = 39%
RCs	4/6 = 67%	2/6 = 33%
Others	7/12 = 58%	5/14 = 36%

Table 2.13-2 — Perceived Value of Emergency Tools

Use of Emergency Tools

The data indicate that most respondents who have emergency tools consider them “essential” reliability tools for situational awareness. The survey data also reveal that emergency tools are not used as widely as more common, readily available tools/applications such as the state estimator or contingency analysis. Fewer respondents answered the emergency tools part of the survey than responded to sections concerning other tools/applications. Table 2.13-3 summarizes respondents’ use of the emergency tools. RCs are listed separately.

Application	Do You Have this Emergency Tool?			Do You Use this Emergency Tool?		
	All	RCs	Others	All	RCs	Others
Residential load or DSM	6/20 = 30%	2/6 = 33%	4/14 = 29%	6/6 = 100%	2/2 = 100%	4/4 = 100%
Commercial/industrial load or DSM	12/20 = 60%	3/6 = 50%	9/14 = 64%	12/12 = 100%	7/7 = 100%	5/5 = 100%
Load reduction by voltage reduction	6/20 = 30%	2/6 = 33%	4/14 = 29%	6/6 = 100%	2/2 =1 00%	4/4 = 100%
Rotating load shed	17/20 = 85%	4/6 = 67%	13/14 = 93%	12/17 = 71%	4/4 = 100%	8/13 = 62%

Table 2.13-3 — Use of Emergency Tools/Applications

The primary finding of this survey section is that certain types of emergency tools are not widely available or used within the industry. Table 2.13-3 shows that rotating load shed is the most commonly used operational emergency tool, as reported by a relatively small number of respondents. The recommendations made in Section 3.5, Load-Shed Capability, regarding documented practices for keeping operators aware of the status, availability, magnitude, and time-to-deploy of all load that can be shed on an emergency basis, should be considered in the context of the recommendations made below.

Recommendations for New Reliability Standards

RCs prepare reliability assessments, provide a wide-area view of reliability, and coordinate emergency operations in real time for one or more balancing authorities. As specified in requirement R4 of Standard IRO-005, one of their responsibilities is:

> [A]s portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.

Standard IRO-005 (requirement R3) does not stipulate that the RC must have direct control over load shedding. The standard does specify, however, that RCs have the authority to direct load shedding when necessary. Reliability coordinators are not currently required to be aware of the system load-shed capability required to address a potential or actual IROL violation

Recommendation – S15

Provide real-time awareness of load-shed capability to address potential or actual IROL violations.

RTBPTF Recommendation

Based on survey results, RTBPTF developed a proposed requirement and performance measure to clarify that RCs must be kept aware of load-shed capability in particular because that factor is critical to the ability to address a potential or actual IROL violation.

RTBPTF recommends that Standard IRO-005 be enhanced to require the RC to be aware of the load-shed capability needed to address a potential or actual IROL violation within its area of responsibility. RTBPTF developed the following proposed requirement (PR):

PR1. Each Reliability Coordinator shall have real-time awareness of load-shed capability needed to address a potential or actual IROL violation within its area of responsibility.

RTBPTF developed the following proposed measure (PM) for the above requirement.

PM1 Each Reliability Coordinator shall be required to demonstrate system load-shed capability by having a display (or visualization technique) that shows the real-time status and amount of MW available for shedding load within its area of responsibility.

Rationale

The rationale for this recommendation is discussed extensively in Section 3.5, Load-Shed Capability. Current NERC standards assign RCs the authority to direct their TOPs and BAs to shed load, and TOPs and BAs are required to comply with those directives. No standards, however, specifically mandate that RCs maintain situational awareness of the capability to shed load under real-time operating situations. But the RC must know what can be achieved in response to a directive to shed load.

Recommendations for New Operating Guidelines

RTBPTF is not recommending operating guidelines related to emergency tools.

Recommendation – A14

Research how emergency tools and visualization techniques are used in load shedding plans.

Areas Requiring More Analysis

The survey results are insufficient to establish how personnel use emergency tools, including whether any documented procedures are associated with the tools. RTBPTF recommends further analysis in the following two areas related to emergency tools:

- Research the ways load-shedding plans are established in relation to the various emergency tools. In particular, how does the industry coordinate and prioritize the use of emergency tools (i.e., rotating load shed) with automatic load-shedding schemes? Is there variation in practices and implementation?
- Research current techniques and devices for showing operators the status of load-shed capability. How does the operator know how much load the

emergency tool can shed? How is load-shed capability calculated? What visualization techniques are used to display this information?

Examples of Excellence

RTBPTF did not identify any Examples of Excellence related to emergency tools.

Section 2.14
Other Tools (Current and Operational)

Definition

This section of the report reviews reliability tools for situational awareness that are currently available and operational and that are not specifically addressed in other sections. The tools/applications that are discussed are listed below with their respective definitions:

- Congestion Management Application — This tool relieves network congestion within an entity's service territory using operational means that lie within the entity's control authority, i.e., generation redispatch, curtailment of economic transactions within the entity's service area, switching in capacitor banks, opening low-voltage lines, etc. Typically, this tool would be a security-constrained economic dispatch program, an optimal power-flow program, or an heuristic program that searches for the best solution from a set of options. For an ISO or an RTO, this may be part of the LMP application.

- Inter-Regional Real-Time Coordination for Congestion Management Application — This tool may be different from the congestion management application listed above if the entity uses a separate tool for managing congestion caused by transactions that originate and/or terminate outside of the entity's service area. This may also be the NERC IDC if used for managing congestion that involves curtailing transactions outside of the entity's service territory.

- Inter-Regional Real-Time Coordination for Market Redispatch — This tool is to adjust the market dispatch within the entity's service territory in coordination with adjacent RCs to manage the inter-regional congestion problem in real time. This tool may be handled by the entity's congestion management application, or it may be handled through a different process.

- Inter-Regional Voltage Profile Coordination. This tool coordinates the voltage profiles between two or more regions. This application may contain features such as wide-area voltage contour visualization, voltage schedule coordination between regions, etc.

- Short-Term Hydro Scheduling. This real-time tool manages deviations from the long-term optimized schedule for reasons of reliability, e.g., a response to a disturbance control standard (DCS) event, acquiring support for localized voltage control, etc.

- Short-Term Wind Energy Forecasting — This near-real-time tool is used to predict and manage generation in response to the variability of supply from wind energy sources.

- Short-Term Load Forecasting — These tools predict short-term (next 0-60 minutes) loads based on parameters such as short-term weather effects, current load, etc. The results from this tool could be used for predictive redispatch, look-ahead contingency analysis, awareness of scheduled non-conforming load changes, etc.

- Short-Term Weather Forecasting — This tool predicts short-term (next 0-60 minutes) extreme weather that may impact operations, i.e. a lightning prediction tool, Doppler radar, etc.

Summary of Findings

The other tools (current and operational) section of the Real-Time Tools Survey was designed to identify tools that provide advanced functionality and are used widely throughout the industry. With the possible exception of congestion management and short-term load forecasting tools, survey results suggest that usage of advanced functions is not prevalent among survey respondents.

The applications described above may provide entities with enhanced situational awareness for monitoring and assessing conditions or performing actions to maintain the reliability of interconnected bulk electric systems. Based on survey results, however, the applications are not used as widely as the typical suite of reliability analysis applications readily available to the industry (i.e., the state estimator or contingency analysis).

Because so few respondents identify themselves as BAs, the task force could not develop statistically significant conclusions for that group. Therefore, the discussion below focuses on RCs and TOPs.

Prevalence of Tools

Table 2.14-1 summarizes responses from RCs and TOPs to survey questions regarding use of advanced tools. For the RCs and TOPs responding, congestion management, short-term weather forecasting and short-term load forecasting were the only applications available to at least 50 percent of respondents. Even though a limited number of overall survey participants responded to questions in this section, the results suggest that these three applications are more prevalently used than the others that were specifically identified.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, “32/38=84%” means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

Application	Application Available?			Application Operational?		
	All	RCs	TOPs	All	RCs	TOPs
Congestion management	11/41 = 27%	**7/14 = 50%**	4/24 = 17%	10/13 = 77%	6/8 = 75%	4/5 = 80%
Inter-regional real-time coordination of congestion mgt.	8/38 = 21%	6/13 = 46%	2/22 = 9%	8/9 = 89%	6/6 = 100%	2/3 = 67%
Inter-regional real-time coordination of market redispatch	3/31 = 10%	3/12 = 25%	0/17 = 0%	3/4 = 75%	3/3 = 100%	0/1 = 0%
Inter-regional voltage profile coordination	1/31 = 3%	1/12 = 8%	0/17 = 09%	1/3 = 33%	1/2 = 50%	0/1 = 0%
Short-term hydro scheduling	5/32 = 16%	4/11 = 36%	1/18 = 6%	3/4 = 75%	2/3 = 67%	1/1 = 100%
Short-term wind energy forecasting	1/31 = 3%	0/10 = 0%	1/18 = 6%	1/4 = 25%	0/1= 0%	1/3 = 33%
Short-term load forecasting	13/29 = 45%	**7/9 = 78%**	5/17 = 29%	12/14 = 86%	6/7 = 86%	5/6 = 83%
Short-term weather forecasting	14/30 = 47%	4/10 = 40%	**10/17 = 59%**	14/15 = 93%	4/4 = 100%	10/11 = 91%

Table 2.14-1 — Prevalence of Tools/Applications

Perceived Value of Tools

Although the tools may not be used widely throughout the industry, respondents who report having operational tools tend to rate them “essential” or “desirable” for situational awareness. The tools most widely used are those related to congestion management (see Table 2.14-2). One respondent notes that its congestion management tool is “a key component of our congestion management tool for the Inter-ties and is effective.”

Application	Rated “Essential”			Rated “Desirable”		
	All	RCs	TOPs	All	RCs	TOPs
Congestion management	8/13=62%	6/8=75%	2/5=40%	4/13=31%	2/8=25%	2/5=40%
Inter-regional real-time coordination for congestion management	6/9=67%	4/6=67%	2/3=67%	2/9=22%	1/6=17%	1/3=33%
Inter-regional real-time coordination for market re-dispatch	1/3=33%	1/3=33%	0/0=0%	1/3=33%	1/3=33%	0/0=0%
Inter-regional voltage profile coordination	1/1=100%	1/1=100%	0/0=0%	0/1=0%	0/1=0%	0/1=0%
Short-term hydro scheduling	2/3=67%	2/2 100%	0/1=0%	1/3=33%	0/2=0%	1/1=100%
Short-term wind energy forecasting	0/3=0%	0/1=0%	0/2=0%	3/3 100%	1/1 100%	2/2=100%
Short-term load forecasting	10/14=71%	6/7=86%	3/6=50%	3/14=21%	0/7=0%	3/6=50%
Short-term weather forecasting	5/14=36%	2/4=50%	3/10=30%	9/14=64%	2/4=50%	7/10=70%

Table 2.14-2 — Perceived Value of Tools/Applications

Recommendations for New Reliability Standards

Because the survey responses indicate that the tools addressed in the “other tools” section are not in common usage throughout the industry, RTBPTF does not recommend any new reliability standards or modifications to standards for these tools.

Recommendations for New Operating Guidelines

RTBPTF does not recommend developing any operating guidelines for any of the tools described in this section. The tools are not in common usage throughout the industry so they do not warrant new operating guidelines.

Recommendation – A15

Analyze the need to use tools for congestion management, voltage profiles, wind-energy forecast, and weather forecast.

Areas Requiring More Analysis

In light of findings (with numerous references to voltage control and congestion management) presented in the *Outage Task Force Final Blackout Report*,[81] RTBPTF does recommend further examination of the NERC IDC and other tools for congestion management and tools for inter-regional voltage profile coordination. RTBPTF also recommends further investigation into tools for load forecasting, wind-energy forecasting, and hydro scheduling because it appears that the industry as a whole would benefit from advances in those areas.

Although the task force developed no recommendations for standards or operating guidelines for these tools, some of them, such as those related to congestion management and inter-regional voltage profiles, are gaining wider acceptance. The task force recommends that these tools and areas of application receive additional analysis.

Only 50 percent of the reliability coordinators and 31 percent of others who responded to the survey indicate they use a tool to help manage congestion. All Eastern Interconnection reliability coordinators, however, are required to use the NERC IDC to manage congestion. Several RTO and ISO entities use a security-constrained economic dispatch application to manage internal and inter-regional congestion and use LMP signals to assist with market redispatch. Because the entities that use security-constrained economic dispatch and LMP applications consider them critical to their ability to maintain system reliability, these tools should be researched further to identify the best available tools and practices and to determine whether standards and/or operating guidelines are needed. Additional research also should be performed on other types of congestion management applications that other entity types use.

Only a few respondents indicate that they possess a specific tool for coordinating inter-regional voltage profiles. Many entities doubtless use other tools and processes for this purpose. Given the relevance of voltage profiles to the August 14, 2003, blackout, the industry should perform further research to ascertain the requirements, current availability/development, and feasibility of implementation for tools to coordinate inter-regional voltage profiles.

Only one respondent describes possessing a tool specifically for forecasting short-term supplies of wind energy. Given the increase in wind energy facilities

[81] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April.

across the country, many entities might benefit from such a tool. The industry should research this tool further to ascertain its requirements, current availability/development, and feasibility of implementation.

Industry members more commonly use tools for short-term hydro scheduling and short-term load forecasting than for wind-energy forecasting. As with short-term wind energy forecasting, short-term hydro scheduling and load forecasting can affect the accuracy of results derived from other applications that utilize these data, such as security-constrained economic dispatch and other tools used for reliability analysis. Therefore, the industry should perform additional research into all three of these forecasting tools to identify the tools and practices that achieve the greatest accuracy.

Although most entities probably subscribe to a commercial weather service, a few may have in-house meteorological staff providing this service. Survey results do not indicate the numbers and types of tools used for short-term weather forecasting. In addition, respondents do not specify what actions they take based on weather-forecast data. Because weather forecast data are typically used as input to load-forecasting tools, they can affect the accuracy of those forecasts. The industry should perform additional research on weather-forecasting tools to identify the tools and practices that achieve the greatest accuracy.

Examples of Excellence

RTBPTF identified the following examples of excellence. Each of the entities described below has developed its own method for using some of the tools/applications described in this section.

RTBPTF cites Bonneville Power Administration's use of a curtailment wizard in their implementation of a congestion management application as an example of excellence (See EOE-13 in Appendix E). This wizard is a key component of the congestion management tool for Bonneville Power's interties.

RTBPTF cites as an example of excellence the use of a real power-voltage (PV) stability analysis tool by FE and MISO that determines system operating limits (See EOE-14 in Appendix E). PV analysis is used to determine the health of the system by determining the rate of voltage decay at a system bus as the level of real power changes because of system loads or transfers across the system.

Section 3.0
Situational Awareness Practices

Introduction

The term "situational awareness" is used numerous times in the blackout reports prepared by NERC and the U.S.-Canada Power System Outage Task Force. The term "situational awareness" is often (and perhaps more accurately) referred to as "situation awareness," which has been described as having three levels: level 1 is the perception of elements, level 2 is comprehending what those elements mean, and level 3 is using that understanding to project future states.[1] In the context of the blackout reports, the "situational awareness" of operators fits this same definition: knowing what is going on around you and understanding what needs to be done and when to maintain, or return to, a reliable operating state.

Situational awareness is a key concept mentioned in nearly every section of this report. Sections 3.1 through 3.7 focus on elements of situational awareness related to operating practices and procedures rather than to any particular tool. That is, the subsections of this section of the report address the practices, processes, and procedures used by organizations to ensure that their operators have the information and guidance they need to be aware of potentially unreliable system conditions and know what effective actions they can take to maintain reliability.

Practices Addressed in the Report

In preparation for the design of the Real-Time Tools Survey, the results of which are the basis for this report, RTBPTF reviewed the then-current NERC Reliability Standards to identify elements of situational awareness that were addressed to some extent in the standards. Many of these elements that relate to the use of real-time tools are addressed extensively elsewhere in this report. The situational awareness practices section of the Real-Time Tools Survey covered practices and procedures that were identified for investigation to determine whether specific requirements or guidelines should be defined for them. The intent of the recommendations in the following section is to clarify the standards in a way that is enforceable.

The Real-Time Tools Survey and the subsections below address situational awareness practices:

- **Section 3.1, Reserve Monitoring** — a documented set of procedures, practices, or guidelines for maintaining awareness of the current and near-term reactive reserve capability and operating reserve capability (i.e., capability above firm system demand required to provide for regulation, load

[1] Endsley, M. R. 1988. "Situation awareness global assessment technique (SAGAT)." *Proceedings of the National Aerospace and Electronics Conference (NAECON).* New York: IEEE. pp.789-795.

forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserve).

- **Section 3.2, Alarm-Response Procedures** — documented instructions for operators to follow when an alarm is issued. These procedures make operators aware of prudent actions to take in an alarm situation. These procedures should not be confused with Operating Guides, which are discussed in Section 3.4, Operating Guides (Mitigation Plans), of this report.
- **Section 3.3, Conservative Operations** — an operational state resulting from intentional actions in response to unknown, insecure, or potentially risky system conditions to move to a known, secure, and low-risk operating posture. For example, the power system is postured differently for an impending hurricane, ice storm, cold front, etc. These practices are primarily proactive and are usually taken in advance of an anticipated event or system condition, as distinguished from reactive practices, such as those discussed in Section 3.6, System Reassessment and Re-posturing. However, conservative operations practices can be employed following some events and can thus be a subset of reassessment and re-posturing.
- **Section 3.4, Operating Guides (Mitigation Plans)** — written procedures or instructions that identify preventive or remedial actions to be taken by operators to mitigate undesirable pre-contingency or post-contingency conditions on the transmission system. Operating guides help operators be aware of the prudent actions to take under various system conditions. Operating guides should not be confused with the procedures discussed in Section 3.2, Alarm-Response Procedures. An operating guide is a situation-specific, proactive mitigation plan for an undesirable pre-contingency or post-contingency condition on the transmission system, as distinguished from an event-specific, reactive response to a specific alarm. In addition, operating guides should not be confused with operating guidelines which are, in the context of this report, prevalent practices of a general nature that are applicable to many reliability entities, as described in the Introduction to this report.
- **Section 3.5, Load-Shed Capability** — documented practices that define how the system operator is kept aware of the status, availability, magnitude, and time to deploy of all load that can be shed on an emergency basis.
- **Section 3.6, System Reassessment and Re-posturing** — documented practices that give guidance to the system operator for returning the system to a secure and studied condition following an event or events that leave the system in an insecure or unstudied state. These practices are primarily "reactive" in that they are usually performed in response to an event, as distinguished from "proactive" practices, such as the conservative operations practices discussed in Section 3.3, Conservative Operations, of this report, which are primarily used in anticipation of an event or system condition. However, conservative operations practices can be employed following

certain events and can thus be a subset of system reassessment and re-posturing.

- **Section 3.7, Blackstart Capability** — documented practices that define how the system operator is to be kept aware of the status and availability of blackstart generating units and transmission paths identified in the system restoration plan as being essential for restoring the system from a blackout. These practices should not be confused with the plans and procedures required by NERC Reliability Standard EOP-005-0, System Restoration Plans. Typically those plans and procedures deal with longer-term issues such as periodic testing of blackstart units and periodic system restoration drills. The specific practices addressed in this section of the report pertain to the near-term or real-time situational awareness of the current state, availability, and capability of the blackstart facilities.

Significance to the August 14, 2003 Blackout

The *Outage Task Force Final Blackout Report* states that NERC Reliability Standards are based on seven key concepts, one of which is emergency preparedness. Organizations need to have a set of plans and procedures in place in advance of any emergency to ensure that operators are aware of the proper course of action to take and capabilities that are available to them when responding to the emergency. The survey questions discussed in Sections 3.1 through 3.7 were designed to determine the availability and usage of the tools, plans, and procedures necessary for responding to significant system events.

For the most part, the necessary "procedures and capabilities" are addressed in the EOP series of NERC reliability standards. However, the *Outage Task Force Final Blackout Report* specifically identifies problems with each of the items identified in Sections 3.1 through 3.7 of this report.

RTBPTF Recommendations for New Reliability Standards

In Sections 3.1 through 3.7, RTBPTF makes several recommendations to add new requirements to existing standards. These recommendations are summarized below.

- RTBPTF recommends that Reliability Coordination — Current Day Operations requirements be revised to delineate specific, independent requirements for monitoring operating reserves and reactive reserves and that specific, independent measures be developed for these requirements.

- RTBPTF recommends that several existing reliability standards be revised and coordinated to include a requirement that each RC and TOP have documented plans and procedures for conservative operations. These plans and procedures shall identify the credible conditions that could lead to an unknown, insecure, or potentially risky operating state and shall identify the appropriate actions operators are expected to take.

- RTBPTF recommends that all existing standards pertaining to mitigating actions shall be coordinated and revised to require that formal operating guides shall be written for each IROL and any SOL or other condition having a potential impact on reliability. When day-ahead or current-day studies indicate the potential for an operating guide to be implemented, the guide shall be reviewed and verified to still be viable given the studied conditions or shall be updated to provide the appropriate guidance.

- RTBPTF recommends standard EOP-003 be revised to require transmission operators and balancing authorities to provide their operators with information sufficient to give them the location, real-time status (in-service or out-of-service), and real-time MWs of load available to be shed via operator-controlled load-shed capabilities. The task force also recommends that standard IRO-005 be revised to require that RCs have the information needed to quickly ascertain the location, time to implement, and available MWs of load that can be shed in response to a directive.

- RTBPTF recommends that NERC Reliability Standard TOP-004-0, Transmission Operations, be revised to include a requirement for each Transmission Operator and Reliability Coordinator to have formal, documented practices and procedures for the reassessment and re-posturing of its system following an event or events that leave the system in an insecure or unstudied state. This recommendation should be considered along with similar recommendations that are made in Section 3.3, Conservative Operations, of this report.

- RTBPTF recommends that requirement R8 of NERC Standard-EOP-005-0, System Restoration Plans, be revised to specifically state that operators be given the information they need to maintain awareness in real time and on a current-day and day-ahead basis of the availability and capability of the blackstart generation resources and transmission cranking paths identified in their system restoration plans. In addition, this requirement should also require that operators be provided documented practices and procedures that identify the specific information to be monitored to ensure the availability and capability of blackstart resources and to identify the actions to be taken in the event that blackstart availability or capability is less than required in the restoration plan.

Section 3.1
Reserve Monitoring

Definition

Reserve monitoring is a documented set of procedures, practices, or guidelines for maintaining awareness of the current and near-term reactive reserve capability and operating reserve capability.[2]

Background

Operating reserves (also known as real or MW reserves) are used to ensure the energy balance for each BA. They tend to globally impact the electrical system, in contrast to reactive reserves, which tend to be more localized. Figure 3.1-1 shows the various types of operating reserve generation that are defined within the NERC Glossary of Terms.[3] Operating reserves consist of both contingency and regulating reserve.

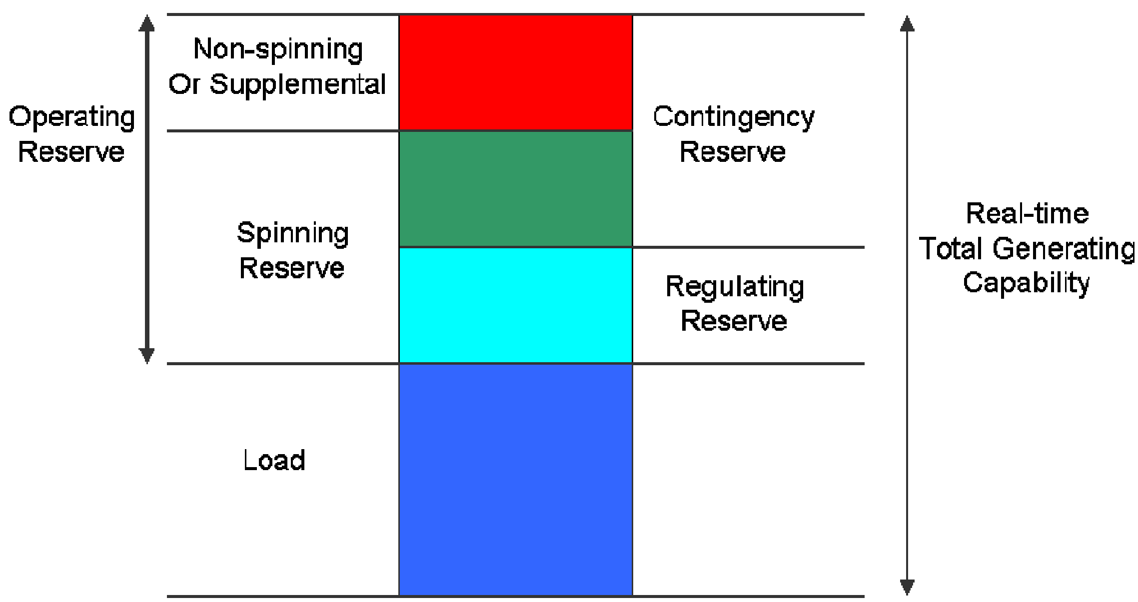

Figure 3.1-1 — Diagram of Reserve Generation, as Defined in NERC Glossary of Terms

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[2] Defined as the capability above firm system demand that is required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserve.

[3] http://www.nerc.com

Summary of Findings

General Questions: Reactive Reserves

The survey results indicate that documented operating practices defining how reactive reserves are monitored are commonly used within the industry. Nearly 63 percent (10 out of 16) of RCs and 52 percent (13 out of 25) of TOPs responding to this section of the survey reported having such procedures. Of the entities that do not currently have documented procedures, most indicate they plan to document reactive reserve practices in the future. This includes all of the remaining RCs and the majority of the remaining TOPs. Of those monitoring reactive reserves, all 10 RCs and 12 of 13 TOPs reported that the function was essential or desirable.

Six respondents took the time to comment on the question of reserve monitoring. Five of those commenting concluded that monitoring reactive reserve levels is essential to ensure proper voltage levels and/or provide inputs to further analysis (PV analysis, analysis of interface limits, voltage stability, etc.) and thus help prevent voltage collapse. One respondent with the capability to calculate reactive reserves operates an ancillary service market for reactive reserve capability that calculates margins.

All RCs and TOPs that have documented practices indicated that control room personnel use them. However, other groups rely heavily on the documented practices, including Operations Support Staff at 60 percent of the RCs and 62 percent of the TOPs, as well as Next-Day Planners at 50 percent of RCs and 31 percent of TOPs who responded. First-line management staff also use the capability, but to a lesser degree (0 percent of RCs and 38 percent of TOPs).

Almost all those reporting (more than 80 percent) indicated that the procedures are published. Some use more than one format to document procedures, as shown in Table 3.1-1.

Documentation Format	RCs	TOPs
EMS Help Systems	40%	15%
Web-based Help systems	30%	0%
Departmental memos/letters	30%	54%
EMS Display Notes	50%	69%
Other	10%	8%

Table 3.1-1 — Documented Practices

A variety of groups were reported as being involved in writing and updating procedures. RCs and TOPs indicated that operations support staff are most heavily involved (100 percent for RCs, 46 percent for TOPs) in documentation of procedures. First-line managers are involved in documenting procedures at 30 percent of RCs and 69 percent of TOPs. Control room personnel and next-day planners are also involved in documentation but to a lesser degree (20 percent at RCs and 38 percent at TOPs). In supplemental comments, one company stated that its EMS vendor is involved in documenting procedures.

A large majority of those reporting (90 percent of RCs, 85 percent of TOPs) reported that procedures are reviewed and updated on an as-needed basis. Forty percent of RCs and 38 percent of TOPs reported that procedures are reviewed annually; no respondents reported reviewing more frequently than once per year. One respondent commented that its procedures are reviewed every 2 years, and another indicated that electronic versions of procedures are updated as needed while hard copies are updated annually.

About 70 percent of RCs and TOPs reported that reactive reserve calculations are performed at SCADA scan rates. Much smaller percentages (0 to 10 percent) reported that calculations of reactive reserves are done weekly, daily or hourly. On-demand triggers are used by 20 percent of RCs and 33 percent of TOPs; event triggers are used by 10 percent of RCs but no TOPs. Forty percent of RCs and 17 percent of TOPs reported that the calculation is initiated for “other” reasons, and several commented that the calculation is performed at the state estimator cycle rate.

The following table shows the responses to the question:

Reactive Reserve Factors	RCs	TOPs
Reactive reserve requirements	50%	33%
Nameplate capabilities of static reactive devices	80%	58%
Voltage-adjusted capabilities of static reactive devices	20%	33%
Design “D-curve” var capabilities of generating units	40%	33%
Field tested and proven var capabilities of gen units	60%	50%
AVR status	50%	33%
Zonal deliverability of reactive reserves	20%	8%
Voltage limits	30%	42%
“n-1” criteria (reserve capability following the next contingency)	20%	42%
In-service/out-of-service status of reactive controllers	50%	50%
static Var compensator (SVC) status	40%	25%
LTC regulating range	0%	42%
SVC operating range	40%	25%
Synchronous condenser capability	50%	8%
Effects of neighboring systems	10%	50%
Others	0%	8%

Table 3.1-2 — Factors considered in the Reactive Reserve Calculation

One of 10 RCs and 4 of 12 TOPs indicate that periodic written reports are used to inform operators of the status of reactive reserves. Some of these respondents indicated that the reports are updated annually. These responses indicate a lack of current, near-term awareness of reactive reserve capability in those control centers. However, the majority reported that dynamically updated displays and/or dashboards are used for operator situational awareness, with multi-purpose “dashboards” used by 70 percent of RCs and 42 percent of TOPs and dedicated displays used by 50 percent of RCs and 67 percent of TOPs. One company uses bar graphs to display unit reactive output and capability and another reports that operators are able to generate detailed reactive capability reports on demand.

The majority of respondents with documented practices indicated that operators are primarily made aware of actual reactive reserve margin deficiencies by audible alarms (56 percent of RCs, 67 percent of TOPs) and by color-coded graphical displays (67 percent of RCs, 33 percent of TOPs). Tabular messages and “other’” mechanisms (nomograms, voltage monitoring on contingencies, voltage alarms, etc.) are used to a lesser extent. No one reported using pop-up messages to make operators aware of reactive reserve margin deficiencies.

Operators are made aware of impending reactive reserve margin deficiencies through a variety of means: audible alarms (11 percent of RCs, 67 percent of TOPs); tabular messages (22 percent of RCs, 25 percent of TOPs); color-coded graphical displays (67 percent of RCs, 33 percent of TOPs); and other means, including nomograms, contingency analysis alarms, voltage alarms at key locations, and notification from RTOs (33 percent of RCs, 42 percent of TOPs). No one reported use of pop-up messages to make operators aware of impending reactive reserve margin deficiencies.

Redispatch (90 percent of RCs, 83 percent of TOPs) and reconfiguration of the electric system (90 percent of RCs, 75 percent of TOPs) were the actions most frequently expected to be taken by operators when, per documented procedures, operators are made aware of reactive reserve margin deficiencies. In addition, 40 percent of RCs and 50 percent of TOPs report that personnel are instructed to change voltage schedules to rectify problems. Several respondents (10 percent of RCs, 25 of percent TOPs) also commented that other operator actions are expected, including load shedding, transformer tap adjustments, switching reactors, and increasing reactive output of units when problems are identified. Small percentages of those responding (10 percent of RCs, 8 percent of TOPs) indicate that no actions would be required unless voltage violations were imminent.

General Questions: Operating Reserves

Of 17 RCs and 25 TOPs responding to the survey questions concerning operating reserves, 88 percent of RCs (15) and 76 percent of TOPs (19) have documented practices defining how operating reserves are monitored. Of those that do not have documented procedures, both RCs and 4 of the 8 (50 percent) TOPs indicated that they planned to document procedures in the future. All 15 RCs that having documented and defined operating reserve monitoring practices indicate that the function is “essential” or “desirable” for situational awareness. Nearly all TOPs (18 of 19) with documented practices defining how operating reserves are monitored rated the value of this practice as “essential” or “desirable” for situational awareness.

Several respondents provided written comments on monitoring operating reserves. The comments indicated that monitoring operating reserves is a “prime resource for system reliability” and should be a requirement for all balancing authorities and “maybe” for TOPs. Other respondents noted:

> “Its one of the most important variables the generator dispatcher must be aware of.”
>
> “…staff needs to know at a glance where operating reserves are available and the amount of reserve available.”

> "Carrying your operating reserves is essential to the reliability of the interconnected transmission system."

Another respondent noted that, in addition to the EMS, operating reserves are tracked by "Market Operation Center web-based reporting tools."

All respondents indicated that control room personnel use operating reserve practices. In addition, about 53 percent of RCs and 33 percent of TOPs reported that next-day planners use the feature. Those reporting also indicate that operations support staff (47 percent of RCs and 61 percent of TOPs) use these practices. More than 30 percent of those reporting indicated that first-line management staff also use the operating reserve practices.

More than 80 percent of those reporting indicate that their operating reserve procedures are published. Some respondents report using more than one format to document procedures, as shown in Table 3.1-3.

Documentation Format	RCs	TOPs
EMS Help systems	20%	22%
Web-based Help systems	27%	17%
Departmental memos/letters	13%	28%
EMS Display Notes	27%	39%
Other	0%	0%

Table 3.1-3 — Formats Used for Documenting Procedures

One respondent clarified that its RTO's written procedures are used for operating reserves.

A variety of groups were reported as involved in writing and updating procedures. RCs and TOPs indicated that operations support staff are most heavily involved (80 percent for RCs, 56 percent for TOPs) in documentation of procedures. First-line management staff are also significantly involved (at 33 percent of RCs and 57 percent of TOPs). Control room personnel are involved in procedure writing and/or updates at only 1 of 15 RCs and 5 of 28 TOPs. Virtually no organizations rely on next-day planners to document operating reserve procedures. Comments reveal that unspecified "reserve groups" or the respondent's RTO or ISO are also involved in documenting operating reserve practices. A large majority of those reporting (100 percent of RCs, 83 percent of TOPs) report that procedures are reviewed and updated on an as-needed basis. Periodic, annual reviews are performed by only 2 of 15 RCs and by 6 of 18 TOPs. No RC reported a periodic review more frequently than once per year; 1 TOP reported a quarterly review/update. One respondent comments that its procedures are reviewed every 2 years.

Eighty percent of RCs and 72 percent of TOPs indicate that operating reserves are calculated at the SCADA scan rate. Smaller percentages of respondents report calculations of operating reserves at less frequent intervals: weekly (7 percent RCs, 0 percent TOPs); daily (13 percent RCs, 11 percent TOPs); and hourly (13 percent RCs, 22 percent TOPs). Additional triggers are also used: on demand (27 percent RCs, 18 percent TOPs); events (13 percent RCs, 6 percent TOPs) and by “others,” such as 4-second, 15-second, 30-second or 5-minute intervals (20 percent RCs, 11 percent TOPs).

Table 3.1-4 illustrates responses to the question regarding which factors are considered in calculating operating reserves.

Operating Reserve Factors	RCs	TOPs
Operating reserve requirements	93%	94%
Seasonal ratings of generating units	60%	61%
Generator reactive loading to maintain voltage schedules	13%	17%
“n-1” criteria (reserve capability following the next contingency)	20%	11%
Historical forced outage rates for generating units	13%	0%
Contributions available from reserve sharing group members	47%	50%
Periodic declared commitments from reserve sharing group members	13%	22%
Firm capacity purchases and sales	47%	78%
Dispatchable load	47%	56%
Quick-start unit capacity	73%	83%
Telemetry	27%	39%
Unit ramp rates	53%	50%
Others	0%	0%

Table 3.1-4 — Factors considered in Operating Reserve Calculation

A clear majority report that operating reserve information is provided to operators via dynamically updated, dedicated displays (73 percent of RCs, 83 percent of TOPs) or dynamically updated, multi-purpose “dashboard” displays for situational awareness (60 percent of RCs, 44 percent of TOPs). Smaller numbers of those responding use periodic written reports (13 percent of RCs, 17 percent of TOPs) to convey information to operators. Only 2 RCs and 1 TOP report using periodic on-line reports. In addition, only 1 RC and 3 TOPs utilize “Other” reporting mechanisms (e.g., SCADA alarms when reserves drop below required levels, unit commitment charts) to convey operating reserve information to operators.

Table 3.1-5 illustrates methods used by the respondents to notify operators of actual deficiencies in operating reserve margins. While tabular messages, pop-up messages and “other” devices are used, operators are most frequently made aware of actual operating reserve margin deficiencies by audible alarms or color-coded graphical displays. The “other” mechanisms used for situational awareness for actual deficiencies include “unit commitment charts,” “online reserve monitors and web based tool …,” “tabular display with color codes,” and “visual indicators on grid wall”). One respondent notes that it has “no alarm, operators monitor,” and another comments that “Alarms” are “under development.”

Table 3.1-5 also illustrates how respondents make operators aware of impending operating reserve margin deficiencies. RCs and TOPs are likely to report impending deficiencies using color-coded graphical displays, “other” means, or tabular messages; audible alarms are not used as extensively as they are to make operators aware of actual operating reserve deficiencies. Pop-up messages are used by only a small percentage of those reporting. “Other” mechanisms for making operators aware of impending operating reserve deficiencies include unit commitment charts, a capacity assessment tool & EMS displays, tabular display with color codes, broadcasts, posted (web) and phone warnings from ISOs, reserve margins, verbal notification, and a periodic manual evaluation process). As above, one respondent reports “No alarm, operators monitor.”

	Actual Operating Reserve Deficiency		**Impending Operating Reserve Deficiency**	
	RCs	**TOPs**	**RCs**	**TOPs**
Audible alarms	47%	61%	8%	35%
Tabular messages	27%	44%	31%	35%
Pop-up messages	7%	17%	8%	12%
Color-coded graphical displays	47%	44%	38%	41%
Others	20%	17%	38%	29%

Table 3.1-5 — Methods of Notifying Operators of “Actual” and “Impending” Operating Reserve Margin Deficiencies

Table 3.1-6 identifies the actions respondents expect operators to take prior to declaring an initial Energy Emergency Alert (EEA-1).The majority of respondents (69 percent of RCs, 89 percent of TOPs) expect operators to recall non-firm sales or redispatch (69 percent of RCs, 67 percent of TOPs) before issuing an EEA-1. Between 30 and 50 percent of RCs and TOPs expect operators to reconfigure the system, enable demand-side management programs for relief, or recall firm sales and/or take other appropriate actions before declaring an EEA-1. Other actions cited in comments included notifying RC and balancing authority; asking for emergency assistance or buying energy in the market; constraining fossil units to maximize total operating reserve; issuing public appeals; sending deployments to bring units on-line; advising various other organizations; constraining generation that has not been offered into the market; requesting voluntary curtailment; curtailing interruptible loads; loading 30 minute (reserves); utilizing all available generation resources; performing supplemental resource evaluations; notifying transmission owners of the possible need for maximum generation; notifying Installed Capacity (ICAP) providers of the possibility of recalling ICAP sales; notifying market participants to activate an emergency demand-response program; and utilizing a reserve-sharing group.

Action	RCs	TOPs
Redispatch	69%	67%
Re-configuration	38%	39%
Recall non-firm sales	69%	89%
Recall firm sales	0%	33%
Demand Side Management	31%	50%
Others	46%	44%

Table 3.1-6 — Actions Operators are Expected to Take Prior to Declaring an EEA-1

Recommendations for New Reliability Standards

Existing NERC reliability standards do not require that operating reserves be calculated or monitored by any entity; entities are only required to have access to and control contingency reserves (BAL-002, R1 and R2) and maintain regulating reserves (BAL-005, R2). RTBPTF recommends that a monitoring requirement be added to the standards to ensure that operators are constantly aware of the available components of operating reserves.

Recommendation – I3

Specify acceptable reactive reserves.

In addition, operating reserves are referenced throughout the standards. In several instances, undefined words are used to refer to a component of operating reserves. This leads to confusion when interpreting the requirements of the standards. Therefore, RTBPTF recommends changes to clarify a term used in the standards.

Recommendation – S16

Require BAs to monitor contingency reserves and calculate contingency reserves at a minimum periodicity of 10 seconds.

RTBPTF Recommendation

To ensure that balancing authorities monitor all of the components of operating reserves, RTBPTF recommends changes to both the contingency and regulating reserve components of the BAL standards. Specifically, RTPBTF recommends that requirement R1 of the BAL-002-0 NERC standard be modified to require that BAs monitor contingency reserves. In addition, the task force recommends a new requirement for the calculation frequency.

PR1. Each Balancing Authority shall ***monitor***, have access to, and/or operate contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

PR2. Each Balancing Authority shall calculate Contingency Reserves at a minimum periodicity of every 10 seconds.[4]

Recommendation – S17

Revise the current-day operations requirements to delineate specific, independent requirements for monitoring operating and reactive reserves

RTPBTF recommends that requirement R2 of NERC standard BAL-005-0 be modified to require that BAs monitor regulating reserves. In addition, the task force recommends a new requirement for the calculation frequency.

PR3. Each Balancing Authority shall ***monitor*** and maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

PR4. Each balancing authority shall calculate Regulating Reserve at a minimum periodicity of every 10 seconds.[5]

[4] To match the update frequency requirement for telemetry data recommended in Section 1.1, Telemetry Data, of this report.

[5] To match the update frequency requirement for telemetry data recommended in Section 1.1, Telemetry Data, of this report.

RTBPTF recommends that requirement R1.4 of IRO-005-2 be modified to refer to Contingency Reserves, to be consistent with the NERC Glossary of Terms.

PR3. System operating (real) and reactive reserves (actual versus required).

Recommendations for Operating Guidelines

Recommendation – G8

Develop a list of the minimum set of items that should be included in the calculations for actual and required operating reserves.

RTBPTF recommends the development of operating guidelines that list the minimum set of items that should be included in the calculations for actual and required operating reserves. These items are listed below:

- Operating reserve requirements
- Facility ratings of generating units (see FAC-008)
- Contributions available from reserve-sharing group members (see BAL-002)
- Firm capacity purchases and sales
- Dispatchable load
- Quick-start unit capacity
- Unit ramp rates

These calculations should be performed at 10-second intervals, and the results should be presented to operators via dynamically updated and dedicated displays, dashboards, or other visualization mechanisms such as those addressed in Section 2.2, Visualization Techniques, of this report.

The task force also recommends that the calculations for actual and required reactive reserves include, at a minimum, the following:

- Nameplate capabilities of static reactive devices
- Field tested and proven var capabilities of generating units
- AVR status
- In-service/out-of-service status of reactive controllers
- Effects of neighboring systems
- Synchronous condenser capability

These calculations should also be performed at 10-second intervals, and the results should be presented to operators via dynamically updated and dedicated displays, dashboards, or other visualization mechanisms, such as those addressed in Section 2.2, Visualization Techniques, of this report.

Areas Requiring More Analysis

RTBPTF did not identify any Areas Requiring More Analysis regarding reserve monitoring.

Examples of Excellence

RTBPTF identified no examples of excellence related to reserve monitoring.

Section 3.2
Alarm-Response Procedures

Definition

Alarm-response procedures are documented instructions that system operators can use to convert alarm data into actionable information. These procedures help system operators know what actions to take in response to a specific alarm.

Background

The *FERC Staff Assessment* identifies a major deficiency in the TOP standards: "While the NERC standards identify the data requirements, they do not identify any minimum acceptable tools and capabilities to turn the data into information necessary to understand critical reliability functions, and therefore the standards lack an important Requirement in this area."[6] This critique applies to many types of system data, but with regard to alarm data, one could argue that alarm-response procedures do convert alarm data into "necessary" information. No NERC reliability standards, however, stipulate specific requirements that would compel RCs, TOPs, or BAs to have documented instructions for operators to follow when an alarm is issued.

Requirement R5 of Standard IRO-002, Reliability Coordination – Facilities, comes close to specifying a requirement for alarm-response procedures when it states that reliability coordinators "shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems . . .." The reference to "alarm management," however, indicates that this requirement is best met by utilizing alarm filtering or other processing methods rather than by having a written response procedure for each alarm.

Requirement R6.6 of Standard TOP-004 requires TOPs to have policies and procedures for responding to IROL and SOL violations. Such violations, which are more serious and complex than many of the alarms typically generated in control centers, are best addressed by specific mitigation plans, which this report refers to "operating guides." Alarm-response procedures are not to be confused with operating guides, which are discussed in Section 3.4, Operating Guides (Mitigation Plans), of this report. The recommendations in Section 3.4 address the concerns that FERC staff raised about providing operator guidance for mitigating undesirable pre- or post-contingency conditions on the transmission system.

Alarm Tools (Section 2.1), Alarm-Response Procedures (this section), and Operating Guides (Mitigation Plans) (Section 3.4) are all used extensively throughout the industry.

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[6] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. Page 103. www.ferc.gov/indus-act/reliability/standards.asp.

These complementary tools should be implemented in a coordinated fashion to maximize an operator's situational awareness, standardize and simplify expected operator actions, and facilitate operator access to reference materials that support the decision-making process. In addition to the procedures discussed in the above-listed sections, the alarm-processing methods (such as alarm filtering) discussed in Section 2.1, Alarm Tools, of this report may prove practical in converting alarm data into actionable information. The alarm-response procedures section of the Real-Time Tools Survey evaluates one component of the integrated set of tools an operator should have for converting alarm data into actionable information.

Summary of Findings

Real-Time Tools Survey responses indicate that industry members commonly use alarm-response procedures. More than 70 percent (32 out of 45) of the respondents to this section of the survey report having documented procedures to inform operators of prudent actions to take in an alarm situation. This number includes 63 percent (10 out of 16) of responding RCs. Almost all (31 out of 32) of those who use documented alarm-response procedures find them an "essential" or "desirable" tool for maintaining situational awareness. A few respondents comment on the value of these procedures, for instance: "With the hundreds of alarms that our SCADA and other systems produce, having a useable, understandable alarm procedure is a must."

Another respondent states, "The response to most alarms is fairly straightforward and does not require a specific written procedure. A written procedure is helpful for those few alarms that require the dispatcher to follow through a more complex response, such as arming special protection schemes or initiating curtailment procedures." Only 2 of the 13 respondents that have no documented alarm response procedures report plans to add such procedures, indicating an apparent lack of perceived need for them. Perhaps some entities have more informative ways of displaying alarm data, and perhaps some control centers lack adequate resources for developing and maintaining alarm-response procedures.

Documentation of Procedures

The survey explored the ways in which alarm-response procedures are documented. Nearly all respondents (27 out of 31) retain procedures in the form of published documents. In addition, 58 percent (18 out of 31) have such procedures available via at least one quick-access method such as Web-based help, EMS display notes, or online help systems. Table 3.2-1 summarizes the responses to this question. The results for "online help systems (EMS)" are similar to the results noted in Section 2.1, Alarm Tools, regarding the availability/functionality of help features in the alarm tools application.

Documentation of Alarm Response Procedures	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Other	Total
Published procedures	X	X	X	X	X	X	X	X	X	X								17	**27**
Online help systems (EMS)						X												6	**7**
Web-based help systems (other)						X	X			X								1	**4**
Departmental memos/letters		X		X			X	X		X								11	**16**
EMS display notes (e. g., notes on substation one-line displays)		X		X		X												9	**12**

Table 3.2-1 — Documentation of Alarm-Response Procedures

Need for Quick Access

Two respondents emphasize the need for quick access to documented procedures. One respondent comments, “Because of the large amount of documentation for reliability coordinators, better use of SCADA reference pages should be explored to allow the operator convenient display of related documents/procedures.” Another respondent expands on this topic, as follows:

> EMS ‘on screen’ procedure identifiers are key examples of best practice operations. Unusual events and conditions requiring operator action are often specific to a particular station, plant, line, etc. Procedure identifiers become ‘quick reference’ tools that assist in precise real-time decision-making. Example: solar magnetic disturbances (SMD) – by utilizing alarm response procedures for a SMD we can view established limits and identify correct actions to be taken to protect specific transformers.

Although this last comment may blur the distinction between alarm-response procedures and operating guides (discussed in Section 3.4, Operating Guides (Mitigation Plans)), it emphasizes the importance of ensuring that guidance is available quickly to operators whenever significant levels of information must be processed under stressful circumstances.

Recommendations for New Reliability Standards

The survey responses do not justify developing a recommendation for a new requirement to mandate a written response procedure for all the types of alarms that can be generated in a control center. As one respondent points out, many alarms can be dealt with in a straightforward manner; documented guidance is helpful only when complex situations arise. In addition to alarm-response procedures, other alarm-processing methods that are discussed in Section 2.1, Alarm Tools, of this report (such as alarm filtering) may prove to be practical ways to convert alarm data into actionable information for operators.

Recommendation – G9

Provide written alarm response procedures via at least one quick access method such as Web-based help or on-line help system.

Recommendations for Operating Guidelines

Based on survey responses, RTBPTF recommends that an operating guideline be developed to encourage providing operators (when requested) with written alarm response procedures that are usable, understandable, and available via at least one quick-access method such as Web-based help, EMS display notes, or an online help system. RTBPTF recommends that the method for accessing the procedures be tied directly to the alarm tools application. That is, when an operator receives an alarm, the alarm entry itself should provide a direct method (e.g., by clicking on an icon on the entry) to access the response procedure pertaining to that alarm.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for alarm-response procedures.

Examples of Excellence

RTBPTF identified no examples of excellence for alarm-response procedures.

Section 3.3
Conservative Operations

Definition

Conservative operations encompass actions taken in response to unknown, insecure, or potentially risky system conditions in order to move to a known, secure, and low-risk operating posture. Undertaking conservative operations produces a known, baseline condition in the face of unknown or insecure conditions, thereby enhancing system reliability. Conservative operations produce an operating state in which system operators can be confident and from which they can better focus their preparations for worsening conditions or contingent events. System operators employ conservative operations, for example, to posture a power system in response to an impending hurricane, ice storm, or cold front.

Conservative operating practices are primarily proactive, taken in advance of an anticipated event or system condition, as distinguished from reactive practices such as the reassessment and re-posturing practices described in Section 3.6, System Reassessment and Re-posturing, of this report. Conservative operations practices, however, can be employed following certain events and thus can be a subset of reassessment and re-posturing practices, as noted in Section 3.6.

Background

Requirement R4 of NERC Reliability Standard TOP-004-0, Transmission Operations, states that, "If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes." Requirement R5 of NERC Standard TOP-001-0, Reliability Responsibilities and Authorities, requires TOPs to inform their RCs and other affected entities of real-time or anticipated emergency conditions and to take actions to avoid or mitigate those situations. Neither standard establishes performance measures for those requirements or otherwise gives guidance on acceptable compliance. Having documented practices for conservative operations would promote confidence and consistency in the actions operators take to avoid or mitigate threatening conditions or events.

Summary of Findings

Survey results reveal that most respondents have documented practices for identifying and responding to situations that call for initiating conservative operations. Several survey respondents offer testimonials regarding the value of conservative operations practices, such as the respondent who comments that because of such practices, "Consistency among system operators is greatly enhanced." Another respondent states, "It is essential that operators have documented procedures to follow to prepare for impending risky or insecure operating states." One respondent eloquently expresses why conservative operations practices are essential:

> A conservative operation stance puts the system at a known baseline state when there is a high probability of events (or a sequence of events) occurring that are not normally covered by operating within the reliability criteria. Starting at an unstressed, known operating point gives system operators the time to determine what has happened and what actions to take.

Respondents report having documented a range of actions to effect conservative operations. Because there currently is no requirement to have documented practices or procedures for conservative operations, the task force recommends that a subset of the most prevalent and effective procedures uncovered by the survey be formalized into required practices. The new requirement should identify events that call for conservative operations and stipulate the appropriate, event-specific control actions (or means of developing appropriate control actions) for enacting conservative operations.

Documentation of Practices

Most survey respondents report having documented practices for conservative operations. A little more than half of the respondents to this section of the survey (24 out of 46), including 75 percent (12 out of 16) of RC respondents, report having some type of documented practices for identifying conditions under which the system must be moved toward a more conservative operating state and that also describe the actions the system operator is expected to take. Of the respondents who have such documented practices, two-thirds (16 out of 24) consider them "essential" for guiding operator actions. Almost all (23 out of 24) retain such documentation in the form of published procedures. Of the RCs who report having documented practices for conservative operations, 67 percent (8 out of 12) consider them "essential" for situational awareness, and one-third (4 out of 12) consider them "desirable."

A few respondents report other, apparently supplemental, means of documenting practices for conservative operations. Table 3.3-1 identifies the various ways in which respondents document conservative operations practices.

Documentation of Conservative Operations	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	Others	Total
Published procedures	X	X	X	X	X	X	X	X	X	X	X	X					11	**23**
Web-based help systems	X	X	X	X		X											3	**8**
Departmental memos	X		X		X												5	**8**
Online help systems (EMS)	X	X															2	**4**
EMS display notes (e.g., one-line notes)																	2	**2**

Table 3.3-1 — Documentation of Conservative Operations Practices[7]

Conditions that Trigger Conservative Operations

The survey explored what conditions or events would cause the 24 respondents who report having documented practices to implement conservative operations (see Table 3.3-2). A few RCs report a wide range of triggering events, as do a few TOPs and BAs who are not also RCs. Most respondents identify several triggers, which the task force recommends be included in an operating guideline (see Recommendations for New Operating Guidelines later in this section).

[7] RC responses are indicated with "X." Aliases are used as column headers to mask the RC' names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, "RC 1" in any given table is not the same as "RC 1" or the equivalent identifier in another table in this report.

Conditions Triggering Conservative Operations	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	Others	Total
Weather events (e.g., severe storms, floods, or temperature extremes)	X	X	X	X	X	X	X	X	X	X	X					11	**22**
Natural threats to facilities (e.g., forest fires or earthquakes)	X	X	X	X	X	X	X	X	X	X		X				9	**20**
Terrorist threats or sabotage	X	X	X	X	X	X	X	X								7	**15**
Solar magnetic disturbances	X			X		X	X	X		X						3	**9**
Loss of multiple transmission lines, resulting in insecure operations	X	X	X	X	X				X							6	**12**
Unexpected capacity shortfall	X	X	X	X							X	X				7	**13**
Loss of multiple generating units, as through shutdown of a nuclear plant	X	X	X		X						X					5	**10**
Loss of situational awareness (e.g., major loss of telemetry data)	X	X	X	X		X										8	**13**
Voltage degradation in another system	X		X				X		X							5	**9**
Cyber security threats	X	X		X	X											6	**10**
Major loss of load	X				X											7	**9**

Table 3.3-2 — Conditions Triggering Conservative Operations

Documented Actions to be Taken

The survey inquired about what actions are documented as being required or recommended for the system operator to take in response to triggering conditions. The intent of these questions was to determine what is expected of operators when they discover a real-time or potential condition that could cause the system to enter an unknown, insecure, or unreliable operating state. In addition to the tabulated responses summarized in Table 3.3-3, several respondents comment that they take steps to acquire or schedule additional generating capacity and reactive reserves. A few RCs report a wide range of expected operator actions, as did a few TOPs and BAs who are not also RCs. The task force recommends that several of the specific actions that many respondents employ be included in a new operating guideline. As some respondents point out, which actions are appropriate depends on the nature of the current or impending situation.

Documented Actions for Conservative Operations	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC 13**	**RC 14**	**RC15**	**Others**	**Total**
Cancel planned outages	X	X	X	X	X	X	X	X		X	X	X				9	**20**
Lower transfer limits	X	X	X	X	X	X	X	X	X			X				5	**15**
Increase coordination and communication of relevant information	X	X	X	X	X			X		X	X					8	**16**
Perform analysis of multiple contingencies or other credible disturbances	X	X	X		X				X			X				6	**12**
Initiate a “heavy load” voltage procedure (e.g., pre-switch capacitors)	X	X	X					X			X					3	**8**
Staff the backup control center	X					X	X			X						5	**9**
Curtail transfers	X	X	X		X											6	**10**
Use more conservative thermal limits				X			X		X							3	**6**
Reduce ATCs or bring them to zero				X		X										3	**5**

Table 3.3-3 — Documented Actions for Conservative Operations

Recommendations for New Reliability Standards

Requirement R4 of NERC Reliability Standard TOP-004-0, Transmission Operations, states that a situation in which a TOP “enters into an unknown operating state” is considered an emergency. Requirement R5 of NERC Standard TOP-001-0, Reliability Responsibilities and Authorities, requires TOPs to inform their RC and other affected entities of real-time or anticipated emergency conditions and to take actions to avoid or mitigate those conditions. Neither standard establishes performance measures for those requirements or otherwise provides guidance on acceptable compliance.

Recommendation – S18

Establish document plans and procedures for conservative operations.

RTBPTF Recommendations

The RTBPTF recommends that a requirement be added to Standard TOP-001-0 to address plans and procedures for conservative operations. RTBPTF's first proposed requirement (PR) related to conservative operations is given below.

PR1. Each reliability coordinator and transmission operator shall have documented plans and procedures for conservative operations that identify the conditions that credibly could lead to an unknown, insecure, or potentially risky operating state. The plans and procedures, which shall be made available to the entity's operators, shall identify the appropriate actions operators are expected to take to move the electric system to a known, secure, and low-risk operating posture.

RTBPTF developed the following proposed measure (PM) for the proposed requirement above.

PM1. Each reliability coordinator and transmission operator shall document plans and procedures for conservative operations and shall demonstrate the use of those plans and procedures.

RTBPTF also recommends that requirement R4 of NERC Reliability Standard TOP-004-1 be revised to refer to the plans and procedures proposed in PR1 above and to clarify that it is the transmission system (not the operator) that can actually enter into an unknown (to the operator) operating state. RTBPTF's second PR for conservative operations is as follows:

Recommendation – S19

Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes.

PR2. Any situation in which the transmission system for which a transmission operator is responsible enters an unknown operating state (i.e., any state for which operating limits have not been determined) shall be considered to be an emergency. The transmission operator shall restore system operations to respect proven, reliable limits within 30 minutes. The transmission operator shall restore the system based on the plans and procedures for conservative operations stipulated in PR1 of TOP-001-0.

RTBPTF developed the following PM for the proposed requirement above:

PM2. Whenever the transmission system for which a transmission operator is responsible enters an unknown operating state, that transmission operator shall have and upon request provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that can be used to determine whether it restored operations to respect proven, reliable system limits within 30 minutes, in accordance with documented plans and procedures for conservative operations specified in requirement R4.

These recommendations should be considered at the same time as similar recommendations made in Section 3.6, System Reassessment and Re-posturing, of this report.

Rationale

The survey reveals that industry members commonly use documented practices for conservative operations. Current reliability standards that require action in response to an unknown or unreliable operating state lack specificity. The standards should be reinforced by requiring documented practices for conservative operations. Conservative operations produce an operating state in which system operators can be confident and from which they can better focus their preparations for worsening conditions or contingent events. Having documented practices for conservative operations enhances system reliability and promotes consistency in operator guidance and in the actions operators take to avoid or mitigate threatening conditions or events.

Recommendation – G10

Specify the system conditions for initiating conservative operations and action plans to follow during conservative operations.

Recommendations for New Operating Guidelines

The task force recommends that an operating guideline be developed in support of the new requirements for conservative operations proposed above. The operating guideline should stipulate, at a minimum, that the following system conditions should trigger conservative operations:

- Weather events such as severe storms, floods, temperature extremes, or ice (as relevant to the reliability area)

- Natural threats, such as forest fires, volcanoes, or earthquakes (as relevant to the reliability area)
- Terrorist threats or sabotage
- Solar magnetic disturbances (for applicable latitudes)
- Loss of multiple transmission lines, resulting in insecure operations
- Unexpected shortfall in capacity
- Loss of multiple generating units, such as the shutdown of a nuclear plant
- Loss of situational awareness (e.g., major loss of telemetry data or major failure of a critical real-time tool)
- Cyber security threats
- Major loss of load
- Voltage degradation

RTBPTF further recommends that an accompanying operating guideline be developed that, at a minimum, specifies the following operator actions to be taken (as appropriate) if it is necessary to initiate conservative operations.

- Cancel planned outages
- Lower transfer limits
- Increase coordination and communication of relevant information
- Perform analysis of multiple contingencies or other credible disturbances
- Curtail transfers

Alternatively, these operating guidelines may be incorporated in the revised standards recommended above if the standard drafting team and industry response deem that inclusion appropriate.

Areas Requiring More Analysis

RTBPTF recommends no additional areas of analysis for conservative operations.

Examples of Excellence

RTBPTF identified no examples of excellence related to conservative operations.

Section 3.4
Operating Guides (Mitigation Plans)

Definition

Operating guides, also called mitigation plans, are written procedures that identify appropriate preventive or remedial actions that operators should take to mitigate undesirable pre- or post-contingency conditions on the transmission system. An operating guide is a situation-specific, proactive mitigation plan to avoid or repair an undesirable condition, rather than an event-specific, reactive response. Operating guides are vital for providing operators with an understanding (in all appropriate time frames) of the control actions they have available to respond to the types of vulnerabilities and risks that their system studies identify.

Operating <u>guides</u> are not to be confused with operating <u>guidelines</u>, which are, in the context of this report, general practices prevalent at many reliability entities. The NERC glossary defines three other terms that may add to the confusion: operating plan, operating process, and operating procedure. RTBPTF, however, did not find those terms used in any current standards.

Background

Several NERC reliability standards address the need for procedures to direct system operators in mitigating or resolving reliability problems. No standard, however, addresses operating guides in a comprehensive manner that identifies successful control actions. For example, requirement R3 of Standard IRO-005, Reliability Coordination – Current Day Operations, states that RCs are to “initiate control actions or emergency procedures” to resolve IROL violations, but it does not specify a minimally acceptable procedure and even seems to imply that emergency procedures are optional. Neither requirement R3 nor requirement R5 of the same standard, which contains almost identical language, establishes performance measures.

In addition, requirements R6 and R6.6 of Standard TOP-004, Transmission Operations, direct transmission operators to “develop, maintain, and implement formal policies and procedures to provide for transmission reliability,” including “responding to IROL and SOL violations.” Again, however, the requirements neither establish specific performance measures nor identify minimally acceptable procedures.

The *FERC Staff Assessment* notes that the TOP group of standards:

> …does not require that the system be assessed to the same extent in the day ahead planning analysis, nor does it require identification of control actions, implementable within 30 minutes, that are needed to bring the system back to a stable state in order to withstand the next contingency without cascading. This may present a potential vulnerability as operators may not be aware of available control actions or worse may not have control actions, other than firm load

shedding, available to them to adjust the system to a stable state after it incurs its first contingency. This can lead to poor execution and reliability risk after the first contingency has occurred in real-time operations.[8]

This deficiency can be rectified by establishing both appropriate control actions and the time frame in which the system should be assessed to ascertain whether control actions are needed. Requirement R4 of Standard TOP-008, Response to Transmission Limit Violations, addresses time frames somewhat by requiring transmission operators to mitigate SOL violations based on assessments preformed "in all operating time frames." This requirement, however, does not specify whether it applies to day-ahead planning, provides no measures, and does not address control actions or other aspects that the survey found that operating guides tend to include.

Control actions are addressed minimally in requirement R3 of Standard TOP-007, Reporting SOL and IROL Violations. This requirement directs TOPs to "take all appropriate actions" to return the system to within the acceptable bounds of an IROL or SOL. In addition, requirement R4 of this standard directs reliability coordinators to "evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits." Both requirements establish only minimal measures, none of which address the need to develop control actions ahead of time and to document expected actions.

Requirement R17 of Standard IRO-005, Reliability Coordination – Current Day Operations, also compels RCs to evaluate the actions taken to return the system to within the acceptable bounds of an IROL. As with requirement R4 of TOP-007, however, requirement R17 neither establishes any measures nor addresses the need to develop control actions ahead of time and document those expected actions.

Standard IRO-004, Reliability Coordination – Operational Planning, comes closest to addressing the deficiency FERC staff identifies in the TOP standards. Requirement R3 of this standard directs RCs to work with TOPs and BAs to "develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs." Although this requirement addresses control actions and applies to day-ahead studies, it neither stipulates performance measures nor addresses the need to document expected actions.

In addressing the context and preconditions for the blackout of August 14, 2003, Chapter 4 of the *Outage Task Force Final Blackout Report*[9] discusses the adequacy of

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[8] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. p. 102. www.ferc.gov/indus-act/reliability/standards.asp

[9] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April. Chapter 4.

system studies intended to identify mitigating actions that operators can take to avoid endangering reliability under current-day conditions. Specifically, the report states that:

> Reliability coordinators and control areas prepare regional and seasonal studies for a variety of system-stressing scenarios, to better understand potential operational situations, vulnerabilities, risks, and solutions. However, the studies FirstEnergy relied on—both by FirstEnergy and ECAR—were not robust, thorough, or up-to-date. This left FE's planners and operators with a deficient understanding of their system's capabilities and risks under a range of system conditions.[10]

The report goes on to describe the lack of documented mitigation plans or procedures: "The investigation team could not find FirstEnergy contingency plans or operational procedures for operators to manage the FirstEnergy control area and protect the Cleveland-Akron area from the unexpected loss of the Perry plant."[11]

This section examines operating guides as one component of an integrated set of tools designed to convert data into actionable information. The procedures described in Section 2.1, Alarm Tools, Section 3.2, Alarm-Response Procedures, and the current section are used extensively throughout the industry. As noted in Section 3.2, these complementary tools should be implemented in a coordinated fashion in order to maximize each operator's situational awareness, standardize and simplify expected operator actions, and facilitate access to reference materials that support the decision-making process.

Summary of Findings

The Real-Time Tools Survey results indicate that industry members generally utilize operating guides. Exactly 100 percent (45 out of 45) of the respondents to the operating guides section of the survey report having documented procedures for mitigating undesirable conditions on the transmission system. This number includes 100 percent (16 out of 16) of the responding RCs. More than 82 percent (31 out of 32) of the respondents who report using documented operating guides rate them as "essential" for situational awareness. This number includes 15 of the 16 responding RCs. A few survey respondents offer opinions, generally favorable, regarding the value of operating guides, as demonstrated by the following quotations:

> "Operating guides are a necessary tool to define the limitations of the power system, provide guidance on indications of instability [or] other impending problems, and provide guidance for mitigating actions."

> "Operating guides are necessary for quick and efficient mitigation of operational problems."

[10] Ibid. p. 39.
[11] Ibid. p. 42.

"Operating guides are truly essential to the reliability of the interconnect. Without operating guides, operating decisions in a neighboring area could cause reliability concerns in another area."

Users of Operating Guides

Table 3.4-1 summarizes the types of users of operating guides associated with individual RCs and totals the users associated with all other respondents.

Users of Operating Guides	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Control room personnel	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		NR	27	**42**
Next-day planners	X	X	X	X	X	X	X	X	X	X	X	X	X				NR	7	**20**
Operations support staff	X	X	X	X	X		X	X	X								NR	15	**23**
First-line management staff	X	X	X	X	X	X										X	NR	14	**21**
Others	X																NR	1	**2**

Table 3.4-1 — Users of Operating Guides[12]

Writers of Operating Guides

The survey asked who is responsible for writing and updating operating guides. The results, summarized in Table 3.4-2, reveal that the next-day planners associated with RCs are more involved with writing and updating operating guides than is the case for other respondents. Operations support staff and first-line management are heavily involved for all respondents. The involvement of next-day planners in writing operating guides is related to an issue raised in the *FERC Staff Assessment,*[13] which is discussed in depth in the Background subsection above.

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12 Reliability coordinator responses are indicated with "X." Aliases are used as column headers to mask the RCs' names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, "RC 1" in any given table is not the same as "RC 1" or the equivalent identifier in another table in this report.

13 Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

Writers of Operating Guides	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Operations support staff	X	X	X	X	X		X	X	X	X	X	X	X	X		X	NR	19	**33**
Next-day planners	X	X	X	X	X	X	X			X							NR	6	**14**
First-line management staff	X	X	X	X	X	X		X									NR	19	**26**
Control room personnel	X	X				X											NR	9	**12**
Others									X						X		NR	5	**7**

Table 3.4-2 — Writers of Operating Guides

Some respondents indicate that they write or coordinate operating guides in conjunction with various stakeholders, such as market participants. One respondent stated that, “The Security Coordinator actively develops mitigation plans for potential or actual operating events in conjunction with all regional operating entities. All of these plans are discussed on the regional hotline, allowing all regional entities to be involved in and aware of proposed actions in resolving SOL/IROL violations.”

Formats for Operating Guides

The survey explored the various formats in which operating guides are documented. Table 3.4-3 summarizes the responses. The guides of more than 90 percent of respondents to this question (41 out of 45) are in the form of published documents. In addition, approximately 55 percent (25 out of 45) of respondents have operating guides available via at least one quick-access method such as Web-based help, EMS display notes, or online help systems. The need for ready access to operating guides is discussed in the Recommendations for New Reliability Standards subsection below.

Format of Operating Guides	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Published procedures	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	25	**41**
Online help systems (EMS)	X			X	X	X		X				X					NR	5	**11**
Web-based help systems (other)	X	X	X	X	X	X					X			X			NR	3	**11**
Departmental memos/letters	X	X	X			X	X		X				X				NR	13	**20**
EMS display notes (e.g., notes on substation one-line displays)	X	X	X		X		X	X	X	X							NR	9	**17**
Others				X													NR	1	**2**

Table 3.4-3 — Format of Operating Guides

Structure of Operating Guides

The survey asked respondents how operating guides are structured. Table 3.4-4 summarizes the responses. A preponderance of respondents (42 out of 45) have specific operating guides that address specific conditions; only about 58 percent of respondents (26 out of 45) have guides for general conditions. Operating guides appear to focus equally on preventive and remedial actions. RCs in particular indicate flexibility in how they structure operating guides.

Structure of Operating Guides	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Specific guides for specific conditions	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	26	**42**
Generic guides for general categories of conditions	X	X	X	X	X	X	X	X	X	X	X	X			X		NR	13	**26**
Guides focused on preventive actions (pre-contingency)	X	X	X	X	X	X	X	X	X	X	X	X	X	X		X	NR	18	**33**
Guides focused on remedial actions (post-contingency)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		NR	20	**35**
Others																	NR	0	**0**

Table 3.4-4 — Structure of Operating Guides

Focus of Guides

The survey asked about the conditions for which entities have developed operating guides. Table 3.4-5 summarizes the responses and shows that most entities have guides for a wide range of conditions.

Focus of Operating Guides	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Violations of thermal limits	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		NR	25	**40**
Violations of voltage magnitude limits	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		NR	18	**33**
Specific topology configurations	X	X	X	X	X	X	X	X	X	X		X			X		NR	18	**30**
Conditions triggering a special protection scheme	X	X	X	X	X	X	X	X	X			X	X	X			NR	13	**25**
Violations of transfer limits	X	X	X	X	X	X	X	X	X	X	X		X				NR	16	**28**
Violations of power angle limits	X	X	X	X	X	X											NR	3	**9**
Others											X						NR	2	**3**

Table 3.4-5 — Focus of Operating Guides

Documented Actions to be Taken

Key to any operating guide is the set of control actions that it instructs the system operator to take. Table 3.4-6 summarizes survey responses concerning what operator actions the operating guides stipulate. These responses reveal that operating guides contain a wide range of control actions, with most respondents employing the fundamental actions of redispatch, reconfiguration, transaction curtailment, and load shedding.

Documented Actions to be Taken	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**RC17**	**Others**	**Total**
Redispatch on-line generation	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	25	41
Reconfigure transmission facilities	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	22	**38**
Shed load	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	22	**38**
Curtail transactions	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	NR	16	**32**
Switch shunt reactive devices	X	X	X	X	X	X	X	X	X		X	X					NR	14	**25**
Change voltage schedules	X	X		X	X	X	X	X	X	X	X	X	X				NR	10	**22**
Commit or de-commit units	X	X	X	X	X	X	X	X	X		X		X	X	X		NR	8	**21**
Arm SPS	X	X	X	X	X	X						X	X	X	X		NR	8	**18**
Change LTC taps	X	X	X	X				X		X							NR	8	**14**
Notify other entities (e.g., RCs, nuclear stations)	X	X	X	X	X	X			X		X						NR	6	**14**
Change phase-angle regulating (PAR) taps	X	X	X	X			X			X		X					NR	3	**10**
Change control of DC line or FACTS device	X		X		X		X							X			NR	1	**6**
Others								X		X							NR	0	**2**

Table 3.4-6 — Documented Actions to be Taken

Recommendations for New Reliability Standards

The Real-Time Tools Survey responses reveal that many entities have operating guides that both identify appropriate control actions and are developed and updated based on assessments made in appropriate time frames. There remains, however, a need to formally stipulate performance measures and time frames because, as discussed in the Background subsection of this report, although several NERC reliability standards describe procedures for mitigating or resolving reliability problems, none of them addresses this issue in a comprehensive manner that establishes clear and measurable requirements. The standards fail to specify minimally acceptable procedures or performance measures.

The standards should identify both control actions and the time frame in which the system should be assessed to ascertain whether control actions are needed. Current requirements that address control actions establish, at best, only minimal measures and fail to address the need to develop actions ahead of time and document the expected actions in operating guides. Although requirement R3 of Standard IRO-004, Reliability Coordination – Operational Planning, addresses control actions and applies to day-ahead studies, the requirement stipulates no performance measures and fails to address the need to document expected actions in operating guides.

The standards and requirements described in the Background subsection above should be consolidated and expanded to add clarity, substance, and measurability so that all RCs and TOPs understand they must develop, coordinate, maintain, and implement operating guides that identify preventive or remedial actions to mitigate undesirable pre- or post-contingency conditions on the transmission system.

Operating guides are vital to providing operators with an understanding (in all appropriate time frames) of the control actions available to them to respond to the types of vulnerabilities and risks that adequate system studies can identify.

Recommendation – S20

Develop formal operating guides (mitigation plans) and measures for each IROL and any SOL or other conditions having a potential impact on reliability.

RTBPTF Recommendations

RTBPTF recommends that the following requirements in the NERC TOP reliability standards be consolidated or closely coordinated and cross-referenced in order to clearly, completely, and uniformly spell out all requirements and measures for developing and evaluating control actions to mitigate SOL and IROL violations or other undesirable conditions on the transmission system:

- TOP-004, requirement R3
- TOP-004, requirements R6 and R6.6
- TOP-007, requirements R3 and R4
- TOP-008, requirement R4

In addition, RTPBTF recommends that the following IRO requirements be consolidated or closely coordinated and cross-referenced in order to clearly, completely, and uniformly spell out all requirements and measures for developing and evaluating control actions to mitigate SOL and IROL violations or other undesirable conditions on the transmission system:

- IRO-004, requirement R3
- IRO-005, requirements R3, R4, and R17

RTBPTF further recommends that the consolidated or coordinated requirements be expanded to include the following proposed requirements (PRs):

PR1. Formal operating guides shall be written for every IROL, SOL, or other condition, identified in regional or inter-regional planning studies, seasonal assessments, or other near-term operating studies, that could affect reliability.

Recommendation – S21

Review and update operating guides (mitigation plans) when day-ahead or current day studies indicate the potential need to implement an operating guide.

PR2. When day-ahead or current-day studies indicate the potential need to implement an operating guide, that operating guide shall be reviewed and either verified as still viable for the studied conditions or updated to provide the guidance appropriate to the studied conditions.

Recommendation – S22

Provide temporary operating guides (mitigation plans) with control actions for situations that could affect reliability but that have not been identified previously.

PR3. Temporary, less formal operating guides, which primarily identify control actions, shall be written and provided to operators for situations, identified in day-ahead or current-day studies, that could affect reliability but that have not been identified or formally documented previously.

Recommendation – S23

Develop joint operating guides (mitigation plans) for situations that could require more than one RC or more than one TOP to execute actions

PR4. Operating guides for situations that could require that more than one reliability coordinator direct control actions or more than one transmission operator execute actions shall be jointly developed by all reliability coordinators and transmission operators responsible for directing or executing the control actions.

Recommendation – S24

Develop a formal procedure to document the processes for developing, reviewing, and updating operating guides (mitigation plans).

PR5. A formal procedure shall document the processes for developing, reviewing, and updating operating guides.

Recommendation – S25

Incorporate verifiable and traceable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates when modifying operating guides (mitigation plans).

PR6. Those who modify documented operating guides shall follow a procedure that incorporates verifiable and trackable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates.

Recommendation – S26

Write operating guides (mitigation plans) in clear, unambiguous language, leaving nothing to interpretation.

PR7. Operating guides shall be written in clear, unambiguous language, leaving nothing to interpretation.

Recommendation – S27

State the specific purpose of existence for each operating guide (mitigation plan).

PR8. Each operating guide shall state the specific purpose of (or reason for) its existence.

Recommendation – S28

Summarize the specific situation assessment and address the method of performing the assessment in each operating guide (mitigation plan).

PR9. Each operating guide shall summarize the specific assessment of the situation it addresses including the method of performing the assessment.

PR10. The situations assessed shall include, but are not limited to, the following:

- Violations of thermal limits
- Violations of voltage magnitude limits
- Specific topology configurations
- Conditions that trigger a special protection scheme
- Violations of transfer limits
- Violations of power angle limits

Recommendation – S29

Identify all appropriate preventive and remedial control actions in each operating guide (mitigation plan).

PR11. Operating guides shall identify all appropriate preventive and remedial control actions, including, but not limited to, the following:

- Redispatching on-line generation
- Reconfiguring transmission facilities
- Shedding load
- Curtailing transactions
- Switching shunt reactive devices
- Changing voltage schedules
- Committing or de-committing units
- Arming an SPS
- Changing LTC taps
- Notifying other entities (e.g., reliability coordinators, nuclear stations)
- Changing PAR taps
- Changing control of DC line or FACTS device

Recommendation – S30

Develop criteria in operating guides (mitigation plans) to support decisions regarding whether a specific control action should be taken.

PR12. Operating guides shall include decision-support criteria when operators must decide whether a specific control action should be taken.

Recommendation – S31

Incorporate on-line tools that utilize on-line data when operating guides (mitigation plans) require calculations.

PR13. Operating guides that require the operator to perform calculations shall incorporate online tools that utilize online data.

Recommendation – S32

Make operating guides (mitigation plans) readily available via a quick-access method such as Web-based help, EMS display notes, or on-line help systems.

PR14. Operating guides shall be readily available to operators via a quick-access method such as Web-based help, EMS display notes, or online help systems.

RTBPTF recommends that the following proposed measures (PMs) be established for the requirements presented above.

PM1. Each Reliability Coordinator and Transmission Operator must demonstrate a documented procedure for developing, reviewing, and updating operating guides.

PM2. Each Reliability Coordinator and Transmission Operator must demonstrate the operation of all guides and verify that they include all required elements.

PM3. Each Reliability Coordinator and Transmission Operator must demonstrate that operating guides are readily accessible to on-shift operators.

PM4*.* Each Reliability Coordinator and Transmission Operator must demonstrate how the operator will perform the calculations required for any operating guide.

PM5*.* Each Reliability Coordinator and Transmission Operator must demonstrate the logic of any decision-support criteria in the operating guides.

Rationale

As discussed above, the *Outage Task Force Final Blackout Report*[14] and the *FERC Staff Assessment*[15] both emphasize the need for operators to understand control actions available for mitigating undesirable operating conditions or situations on the transmission system. NERC standards currently identify various vague and uncoordinated requirements for procedures, appropriate actions, and action plans to respond to IROL and SOL violations. A unifying standard applicable to all operating guides will provide structure and clarity regarding performance and compliance with the various requirements. All survey respondents already have documented procedures of some sort to guide the operator in mitigating undesirable conditions on the transmission

[14] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April.
[15] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

system. The recommendations and measures proposed above will establish formal, baseline requirements for operating guides that will raise the bar for many reliability entities.

Recommendations for New Operating Guidelines

RTBPTF does not recommend developing operating guidelines for operating guides.

Areas Requiring More Analysis

RTBPTF recommends no additional areas of analysis for operating guides.

Examples of Excellence

RTBPTF identified no examples of excellence related to operating guides.

Section 3.5
Load-Shed Capability

Definition

The Energy Information Administration of the U.S. Department of Energy defines load shedding as the "Intentional action by a utility that results in the reduction of more than 100 megawatts (MW) of firm customer load for reasons of maintaining the continuity of service of the reporting entity's bulk electric power supply system. The routine use of load control equipment that reduces firm customer load is not considered to be a reportable action."[16]

Having the capability to shed electrical load requires knowing the status, availability, magnitude, and time-to-deploy of all load that can be shed on an emergency basis. Operating practices related to awareness of real-time load-shed capability are those documented practices that define how the system operator is kept informed of the status, availability, magnitude, and time-to-deploy of all load that can be shed quickly.

Background

The *Outage Task Force Final Blackout Report* concludes that, had 1,500 MW of load been shed manually or automatically within the Cleveland-Akron area before the outage of the Sammis-Star 345-kV line, the August 2003 blackout could have been averted.[17] In its technical analysis of the blackout, NERC identifies a corrective action to be taken by FE that includes developing the capability to reduce load (by any method or combination of methods) in the Cleveland-Akron area by 1,500 MW within 10 minutes of a directive from FE's RC to do so.[18] To be able to deliver such a response at any time, the TOP must be apprised of the status, availability, magnitude, and time-to-deploy of all load that can be shed by any method or methods. An ongoing awareness of load-shed capability is needed to give all RCs, TOPs, and BAs confidence in their ability to shed load in an emergency situation. Reliability standards, however, do not specify that operators must be given the information needed to maintain situational awareness of their load-shed capability.

NERC Reliability Standard EOP-001-0, Emergency Operations Planning, requires TOPs and BAs to develop, maintain, and implement load-shedding plans. Operators are not, however, required to maintain situational awareness of the probable results of implementing such plans under real-time or developing operating conditions.

NERC Reliability Standard EOP-003-0, Load Shedding Plans, requires TOPs and BAs to have plans for performing operator-controlled, manual load sheds. The standard also requires that

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[16] http://www.eia.doe.gov/glossary/glossary_l.htm

[17] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April. p. 70.

[18] *Technical Analysis of the August 14, 2003, Blackout*: *What Happened, Why, and What Did We Learn?* A report to the NERC Board of Trustees by the NERC Steering Group. July 13 2004. p. 117.

those plans be implementable "in a time frame adequate for responding to the emergency." The standard does not establish a performance measure for this requirement. The *FERC Staff Assessment* found that a major problem with the EOP standards is the failure to specify the amounts and time frames for load shedding capability.[19] FERC staff mentions this deficiency specifically in regard to EOP-003-0[20] and EOP-001-0, about which they state, "load shedding is the option of last resort and must be capable of being implemented in a much shorter time period than 30 minutes."[21] Standards are clearly needed to establish the amounts and time frames for load shedding capability, although those issues are beyond the scope of the Real-Time Tools Survey.

Standard EOP-003-0 also contains requirements pertaining to implementing automatic load shedding via UFLS or UVLS relays, but operators are not required to maintain situational awareness of the availability or effectiveness of those devices or facilities.

Even if requirements regarding amounts and time frames for load shedding capability existed, however, how would an RC know whether the desired response to a directive to shed load could be achieved under real-time operating conditions? And how would the TOP or BA know that it could respond adequately to such a directive? NERC standards give RCs the authority to direct TOPs and BAs to shed load, and those entities are required to comply with such directives. Currently, however, no standards require any of the entities to maintain awareness of their capabilities to shed load under real-time operating conditions.

Summary of Findings

The load-shedding capability section of the Real-Time Tools Survey was intended to assess current operator practices related to maintaining awareness of load-shed capability and ability to utilize that capability in an emergency. Although most survey respondents report having documented practices for maintaining awareness of load-shed capability, the information they monitor varies greatly, as do the actions identified for shedding load. In addition, few respondents report monitoring any aspect of situational awareness of automatic load-shedding devices, either UVLS or UFLS relays.

Documentation of Practices

Survey respondents generally have documented practices for maintaining awareness of load-shed capability. Approximately 74 percent of respondents (34 out of 46) report having some type of documented practices for this function. Of those who have documented practices, more than 66 percent (23 out of 34) consider them "essential" to situational awareness. Current load-shed capability appears to be documented most thoroughly among TOPs,

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[19] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp. p. 42.
[20] Ibid. p. 51.
[21] Ibid. p. 50.

including the RCs who are also TOPs, probably because in most situations only the TOP has direct control over load-shed capability. Table 3.5-1, identifies the types of documentation respondents have regarding their load-shed practices.

Documentation of Load-Shed Practices	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**Others**	**Total**
Published procedures	X	X	X	X		X	X	X	X	X	X	X					18	**29**
Online help systems (EMS)	X	X			X		X	X									5	**10**
Departmental memos			X	X	X												8	**11**
Web-based help systems	X	X	X	X					X								3	**8**
EMS display notes (e.g., one-line notes)	X			X	X	X											10	**14**

Table 3.5-1 — Documentation of Load-Shed Practices[22]

Load-Shed Information Monitored

The survey explored ways in which system operators keep informed of the status of factors related to their load-shed capability (see Table 3.5-2). As a whole, respondents who are TOPs appear to monitor a wide range of information, as do RCs who are also TOPs and 2 RCs who are not TOPs. One RC reports that its system operators monitor the sensitivity factors of load-shed capability on any facilities that are in violation of thermal, reactive, or transfer limits. A few RCs report a much narrower scope of monitored information, and some did not respond to this question.

Load-Shed Information Monitored	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**Others**	**Total**
Control status (availability of load-shedding field equipment)	X	X	X	X	X	X	X	X									9	**17**
Calculated or estimated MW subject to operator-controllable load shedding	X	X	X	X	X	X		X									18	**25**
Control status (availability of load-shed tools)	X	X			X	X	X										15	**20**

[22] Reliability coordinator responses are indicated with “X.” Aliases are used as column headers to mask the RCs’ names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, “RC 1” in any given table is not the same as “RC 1” or the equivalent identifier in another table in this report.

Load-Shed Information Monitored	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	Others	Total
Calculated or estimated MW available from voltage reduction	X	X							X	X	X						4	**9**
Measured feedback of actual load shed following load-shedding/restoration actions	X	X	X	X													9	**13**
Status of SCADA communication link for operator-controllable load shedding	X	X	X		X												12	**16**
Calculated or estimated MW that can be shed within specific time frames (e.g., < 5 min. or < 1 hr)				X		X						X					6	**9**
Measured, calculated, or estimated MW subject to operator-controllable load shedding as a percentage of peak load			X						X								6	**8**
Measured, calculated, or estimated MW subject to operator-controllable load shedding as a percentage of real-time load	X																5	**6**
Calculated or estimated cold-load pickup of shed load			X														4	**5**
Calculated or estimated load recovery rates following a voltage reduction										X							8	**9**

Table 3.5-2 — Load-Shed Information Monitored

In response to survey questions related to automatic load shedding, only 5 RCs report monitoring any aspect of UFLS relays. Three RCs monitor the status, location, and set points of UFLS relays, and 4 monitor, in one manner or another, the amount of load subject to UFLS operations. RCs report monitoring even fewer aspects of UVLS relays. Perhaps these RCs have few (or no) UVLS relay schemes in their reliability areas.

Similarly, few entities who are not RCs (that is, TOPs, BAs, or other respondents) report that their system operators monitor situational capability of UFLS relays. Only 10 respondents report that their operators monitor the status, location, and set points of UFLS relays. Similarly, only 10 respondents monitor, in one manner or another, the amount of load subject to UFLS operations. To put the awareness of UFLS relays into perspective, fewer than half of all respondents (26 out of 55) provide responses to the UFLS relay question, and only about half of those who respond report that their system operators monitor anything related to UFLS relays.

Documented Actions to Be Taken

The survey asked what documented actions system operators are expected to take when load-shed capability is inadequate. These questions were intended to identify what operators are expected to do when they realize (before load shed is needed) that a current lack of available resources or facilities will prevent operator-controlled load-shedding schemes from yielding the hoped-for results. Table 3.5-3 summarizes the responses. The low number of responses might indicate that, industry wide, this issue has not been given much consideration. A few respondents make comments to the effect that if load shed were implemented and the desired results were not achieved, then an attempt would be made to shed additional load.

Expected Actions for Inadequate Load-Shed Capability	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	Others	Total
Notify management	X	X	X	X	X	X	X										13	**20**
Expedite any maintenance activities affecting load-shed capability	X			X	X	X	X	X	X								7	**14**
Dispatch switching personnel to non-SCADA stations to stand by	X	X	X	X	X			X									8	**14**
Notify other entities (e.g., RCs)	X	X	X	X	X	X											11	**17**
Request engineering studies for additional options	X	X	X					X									8	**12**

Table 3.5-3 — Expected Operator Responses to Inadequate Load-Shed Capability

Recommendation – I4

Determine adequate load-shed capability.

Recommendations for New Reliability Standards

All RCs, TOPs, and BAs need confidence in their ability to shed load in an emergency situation, which means they need to be continuously aware of their load-shed capability. Reliability standards, however, do not specify that operators must be given the information needed to maintain situational awareness of load-shed capability.

As noted in the Background section above, NERC Reliability Standard EOP-001-0, Emergency Operations Planning, requires TOPs and BAs to develop, maintain, and implement load-shedding plans. There is, however, no requirement for operators to maintain situational awareness of the probable results of implementing the plans under current or developing operating conditions. In addition, NERC Reliability Standard EOP-003-0, Load Shedding Plans, requires TOPs and BAs to have plans for operator-controlled, manual load shed. The standard requires that these plans be capable of being implemented "in a timeframe adequate for responding to the emergency." The standard, however, does not specify a measure for this requirement.

NERC standards currently assign RCs the authority to direct their TOPS and BAs to shed load, and TOPs and BAs must comply with such directives. No standard, however, specifies that any of these entities must maintain awareness of their capability to shed load under current operating conditions.

Standard EOP-003-0 also contains requirements pertaining to plans for implementing automatic load shedding via UFLS or UVLS relays but does not specify the need for operator awareness of the status of the devices or facilities supporting those plans.

The lack of specific load-shedding directives should be addressed by new requirements in the EOP group of reliability standards.

Recommendation – S33

Provide the location, real-time status, and MWs of load available to be shed.

RTBPTF Recommendation

The RTBPTF recommends that requirements be added to Standard EOP-003-0 to address operator awareness of current load-shedding capability. RTBPTF's proposed requirements (PR) related to load-shedding capability are as follows:

PR1. Each transmission operator and balancing authority shall provide their operators with information sufficient to give them the location, set points, real-time status (in service or out of service), and actual MW of load-shed capability (measured, calculated, or estimated) from the automatic load-shedding schemes (UFLS or UVLS relays) that are installed within the transmission operator's or balancing authority's footprint.

PR2. Each transmission operator and balancing authority shall provide their operators with information sufficient to give them the location, real-time status (in service or out of service), and real-time MW of load available to be shed via the operator-controlled load-shedding capabilities (including voltage reduction) that they are required to be able to implement within an “adequate” time frame.

RTBPTF developed the following proposed measures (PMs) for the proposed requirements above.

PM1. Each transmission operator shall demonstrate via documented procedures, real-time visualization tools, or other dynamically updated media readily accessible to operators, the static and dynamic information provided to operators to fulfill requirement PR1.

PM2. Each transmission operator shall demonstrate via documented procedures, real-time visualization tools, or other dynamically updated media readily accessible to operators, the static and dynamic information provided to operators to fulfill requirement PR2.

Requirement R3 of NERC Standard IRO-005-0, Reliability Coordination – Current Day Operations, stipulates that RCs must “ensure [that] all resources, including load shedding, are available to address a potential or actual IROL violation.” The standard contains no performance measures for this requirement. Because RCs have the authority and responsibility to direct (and ensure the availability of) load shedding, they also should be continuously aware of the number of MW that they can expect will be shed as a result of their directives to shed load by operator-controlled actions, including voltage reduction. In addition, they should be aware of the expected performance of UFLS or UVLS relays in response to abnormal system conditions. The most effective way to ensure this awareness would probably be to delegate responsibility for it to the TOPs and BAs, who would then keep the RC informed.

RTBPTF recommends that a requirement be added to Standard IRO-005-0 to address the need to keep RCs informed of load-shedding capabilities.

PR3. Each reliability coordinator shall be able to ascertain quickly, using information provided by the transmission operators and/or balancing authorities in their footprint (or by other means), the location, time to implement, and available MW of load that can be shed in response to a directive or that can be expected to be shed as a result of an abnormal system frequency or voltage event. Updates should be prepared at a minimum on a by-exception basis, and verifications should be performed at least daily.

RTBPTF recommends the following measure for PR3.

PM3. Each reliability coordinator shall have documented procedures for ascertaining the current load-shed capability of the transmission operators and balancing authorities in his area of responsibility. The reliability coordinator shall maintain a log of the updates made to the information regarding load-shed capability and the verification of that information.

Rationale

Reliability standards related to load-shedding capability are vague and lack specific requirements for providing operators with the information they need to maintain awareness of their load-shed capability under current and developing system conditions. Standard IRO-005, for example, requires RCs to “ensure” the availability of load shedding. This requirement is unachievable unless RCs maintain situational awareness sufficient to engender ongoing confidence that a directive to shed load can be fulfilled. Standard EOP-003 requires transmission providers and BAs to have the capability to shed load in an “adequate” time frame. This requirement is unachievable unless operators have sufficient situational awareness to engender ongoing confidence that they can respond successfully to a directive to shed load.

Many factors underscore the need for the requirements and measures recommended above. These include the failure to take proactive steps to shed load to avert the blackout of August 14, 2003, the FERC staff’s assessment that requirements are needed for the amounts and timing of load-shedding capability, the vague load-shed requirements in the reliability standards, and the findings of the Real-Time Tools Survey.

Recommendations for Operating Guidelines

RTBPTF does not recommend developing operating guidelines for awareness of real-time load-shed capability.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for awareness of load-shedding capability.

Examples of Excellence

RTBPTF cites a load-shedding/rotation and voltage reduction application used by Dominion Virginia Power as an example of excellence (See EOE-15 in Appendix E). This application enhances reliability and situational awareness by allowing quick response to a load-shed directive and overview monitoring of load shed facility availability and expected response.

Section 3.6
System Reassessment and Re-posturing

Definition

Reassessment and re-posturing of an electrical transmission system entail control actions that return the system to a secure and studied condition following one or more events, such as an overload, that place the system in an insecure or unstudied state. Control actions associated with reassessment and re-posturing of a system include identifying, evaluating, and correcting. Documented operating practices related to reassessment and re-posturing of a system are primarily reactive in that they usually are performed in response to an event.

Reassessment and re-posturing should be distinguished from proactive practices, such as the conservative operations practices discussed in Section 3.3, Conservative Operations, of this report, which are used primarily in anticipation of an event or system condition. Because conservative operations practices can also be employed following certain events, however, they can form a subset of practices related to reassessment and re-posturing of a system, as indicated in Table 3.6-2 below and in the subsequent recommendations.

Background

Chapter 7 of the *Outage Task Force Final Blackout Report* includes an examination of causal factors common to all major outages during the past 40 years.[23] One cause common to several events (including the August 14, 2003 blackout) is that some operators performed "no reassessment of system conditions following the loss of an element and [no] readjustment of safe limits."[24] The report goes on to repeat the following recommendation from past events: "Following a contingency, the system must be returned to a reliable state within the allowed readjustment period. Operating guides must be reviewed to ensure that procedures exist to restore system reliability in the allowable time periods."[25]

The current NERC reliability standards closely related to this recommendation are limited in scope and specificity. Some fail to address reassessment and readjustment, and others fail to require documentation of necessary procedures.

Requirement R6 of NERC Reliability Standard TOP-004-0, Transmission Operations, requires that TOPs have formal policies and procedures that provide for transmission reliability. Several subrequirements of R6 identify the activities those policies and procedures should address, but none specifically includes the reassessment and re-posturing of a system following an event or events that leave the system in an insecure

[23] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April. pp. 107–110.
[24] Ibid. p.108.
[25] Ibid.

or unstudied state. Although subrequirement R6.6 comes close, it refers only to responding to IROL or SOL violations. Other situations may require a system to be reassessed or re-postured. For example, requirement R4 of Standard TOP-004-0, Transmission Operations, states that a situation in which a generating or transmission facility “enters into an unknown operating state” is to be considered an emergency, and operations must be restored “to respect proven reliable power system limits within 30 minutes.” This requirement, however, does not specify the need for documented procedures.

Requirement R17 of NERC Standard IRO-005-1, Reliability Coordination—Current Day Operations, requires RCs to evaluate the impacts of an SOL or IROL violation and decide whether the actions being taken are appropriate and sufficient. Of all the requirements in this standard, R17 comes closest to addressing reassessment and re-posturing, but its scope is limited to SOL and IROL violations. It also does not require that RCs have documented practices or procedures for the prescribed evaluations and determinations. This deficiency in the IRO standard is the same as the one discussed above in relation to the TOP standards.

The *FERC Staff Assessment* notes that the TOP group of standards:

> …does not require identification of control actions, implementable within 30 minutes, that are needed to bring the system back to a stable state in order to withstand the next contingency without cascading. This may present a potential vulnerability as operators may not be aware of available control actions or worse may not have control actions, other than firm load shedding, available to them to adjust the system to a stable state after it incurs its first contingency. This can lead to poor execution and reliability risk after the first contingency has occurred in real-time operations. [26]

Summary of Findings

The reassessment and re-posturing section of the Real-Time Tools Survey evaluates the prevalence and types of documented actions to be taken to reassess and re-posture a system following an event or events that render it insecure or unstudied. Survey results reveal that a majority of respondents have documented practices related to reassessing and re-posturing their systems. The results also reveal that respondents have documented a range of actions for reassessing and re-posturing the system.

Documentation of Practices

The survey responses reveal that industry members generally possess documented practices for reassessment and re-posturing of their systems. Approximately 61

[26] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation’s Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp. p.102.

percent of respondents to this section of the survey (28 out of 46), including 88 percent (14 out of 16) of the RCs who responded, report having some type of documented practices that guide the operator in reassessing and re-posturing the system.

More than 78 percent (22 out of 28) of those who have documented practices consider them “essential” for guiding operator actions and maintaining system reliability. Of the RCs who report having such documented practices, 93 percent (13 out of 14) consider them “essential” for situational awareness and the remaining RC considers them “desirable” for situational awareness. These results represent an impressive endorsement of the necessity for these practices.

All respondents who have documented practices (28 out of 28) have them in the form of published procedures. A few report one or more other, apparently supplemental, means of documenting practices for reassessing and re-posturing the system. Table 3.6-1 identifies the ways in which practices are documented.

Documentation of Reassessment and Re-posturing Practices	**RC1**	**RC2**	**RC3**	**RC4**	**RC5**	**RC6**	**RC7**	**RC8**	**RC9**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**Others**	**Total**
Published procedures	X	X	X	X	X	X	X	X	X	X	X	X	X	X			14	**28**
Web-based help systems	X		X	X	X			X		X							1	**7**
Departmental memos		X	X	X		X	X		X								5	**11**
Online help systems (EMS)	X	X															2	**4**
EMS display notes (e.g., one-line notes)	X																3	**4**

Table 3.6-1 — Documentation of Reassessment and Re-posturing Practices[27]

Several respondents’ comments indicate that entities employ various methods for categorizing and presenting these practices. In several control centers, the practices are incorporated into various separate but related procedures rather than being captured in a single procedure or set of procedures specific to the topic. More than 90 percent of respondents (26 out of 28) report having specific guides for specific conditions, and more than two-thirds (19 out of 28) report having generic guides for general categories of conditions. Seventeen respondents have both. Half of the respondents (14 out of 28) indicate that their documented guides are in the form of checklists of actions to be taken. How the documentation is structured or categorized may not be important, but the necessity of having such documentation is summed up by one respondent as follows: “Guidance and procedures for calculating new reliable

[27] Reliability coordinator responses are indicated with “X.” Aliases are used as column headers to mask the RCs’ names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, “RC 1” in any given table is not the same as “RC 1” or the equivalent identifier in another table in this report.

operating limits, redispatch of generation, communication and notification, etc., are necessary when operators [are] assessing and responding to unplanned events."

Documented Actions to be Taken

The survey also inquired about the tasks, functions, or other actions specified in the documented practices of the 28 respondents who report having them. Table 3.6-2 summarizes the responses. Some RCs report having a comprehensive set of documented actions, as do some TOPs and BAs who are not also RCs. Several actions that are taken by a majority of respondents should be included in an operating guideline for the industry as a whole.

Documented Actions for Reassessment and Re-posturing	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	Others	Total
Communicate and coordinate with neighboring systems	X	X	X	X	X	X	X	X	X	X		X				11	**22**
Verify situational awareness	X	X	X	X	X			X	X		X					8	**16**
Initiate conservative operations	X	X	X	X	X	X	X		X							10	**18**
Verify data availability	X	X	X	X			X	X			X					8	**15**
Reassess, recalculate, or reverify SOLs	X	X	X	X		X				X						5	**11**
Reassess, recalculate, or reverify IROLs	X	X	X	X		X				X						5	**11**
Verify tool availability	X	X	X	X							X					5	**10**
Assess voltage stability	X	X			X							X				5	**9**
Assess transient stability	X				X											2	**4**
Assess dynamic stability	X															2	**3**

Table 3.6-2 — Documented Actions for Reassessment and Re-posturing

Recommendations for New Reliability Standards

Because there currently is no requirement for documented practices or procedures related to reassessment and re-posturing, RTBPTF recommends that a subset of the most prevalent and appropriate procedures revealed by the Real-Time Tools Survey be formalized into required practices.

As noted in the Background subsection above, the *Outage Task Force Final Blackout Report* underscores that, "Following a contingency, the system must be returned to a reliable state within the allowed readjustment period. Operating guides must be reviewed to ensure that procedures exist to restore system reliability in the allowable time periods"[28] and the current NERC reliability standards that closely relate to this recommendation either fail to address reassessment and readjustment or fail to require documentation of necessary procedures. Requirement R17 of NERC Standard IRO-005-1, Reliability Coordination – Current Day Operations, comes closest to addressing reassessment and re-posturing, but its scope is limited to SOL and IROL violations, and it does not require documented practices or procedures. The FERC Staff Assessment also calls for documented practices and procedures for reassessing and re-posturing a system.

Recommendation – S34

Establish documented procedures for the reassessment and re-posturing of the system following an event.

RTBPTF Recommendations

RTBPTF recommends that NERC Reliability Standard TOP-004-0, Transmission Operations, be revised to include a requirement that each transmission operator and reliability coordinator have formal, documented practices and procedures for the reassessment and re-posturing of the system following an event or events that leave the system in an insecure or unstudied state. RTBPTF further recommends that NERC Standard IRO-005-1, Reliability Coordination—Current Day Operations, be revised to include a requirement that reliability coordinators have formal, documented practices and procedures to evaluate whether the actions being taken by transmission operators are effective responses to the event or events that left the system in an insecure or unstudied state. These documented practices should also address appropriate control actions if the evaluation indicates that the transmission operator's response is ineffective or insufficient. The goal of these practices is to help operators identify appropriate control actions (or means of developing appropriate control actions) for reassessment and re-posturing of the system.

RTBPTF recommends that the requirement below be added to Standard TOP-004-0 to establish procedures for reassessment and re-posturing of the system following an event or events that place the system in an insecure or unstudied state. This recommendation should be considered along with similar recommendations made in Section 3.3, Conservative Operations, of this report. RTBPTF's proposed requirement (PR) related to reassessment and re-posturing of a system is as follows:

PR1. Each reliability coordinator and transmission operator shall create and maintain formal, documented practices and procedures for the reassessment and re-

[28] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 108.

posturing of its system following an event or events that leave the system in an insecure or unstudied state.

RTBPTF developed the following proposed measure (PM) for the proposed requirement above:

PM1. Each reliability coordinator and transmission operator shall demonstrate the performance of its documented practices and procedures for the reassessment and re-posturing of its system by conducting a simulation of an event that leaves the system in an insecure or unstudied state or by providing operator logs and other records and reports of actions taken following an actual event.

RTBPTF also recommends that a new requirement be added to Standard IRO-005-1 to address the RC's reassessment of the system.

PR2. Each reliability coordinator shall create and maintain formal, documented practices and procedures related to reassessment of its system to evaluate the appropriateness of the actions being taken by transmission operators in the reliability coordinator's footprint following an event or events that leave the system in an insecure or unstudied state. These documented practices and procedures shall also address appropriate control actions or re-posturing of the system in case the reliability coordinator's evaluation indicates that the transmission operator's actions are inappropriate or insufficient.

PM2. Each reliability coordinator shall demonstrate the performance of its documented practices and procedures for evaluating whether the actions being taken by transmission operators in the reliability coordinator's footprint are appropriate by conducting a simulation of an event that leaves the system in an insecure or unstudied state or by providing operator logs and other records and reports of actions taken in response to an actual event.

Rationale

Failure to adequately reassess and re-posture the transmission system following contingency events has been one of the causes common to several major, historical outages, including the blackout of August 14, 2003. The proposed recommendations above, which will add scope and specificity to current reliability standards, are necessary to provide operators with the information and guidance they need to perform reassessment and re-posturing. The *FERC Staff Assessment* of the TOP series of standards supports these recommendations. The Real-Time Tools Survey findings establish that documented procedures for reassessing and re-posturing the transmission system following a contingency event are prevalent within the industry. The recommendations proposed above will establish formal, uniform requirements for documented and demonstrable practices and procedures that will raise the bar for many reliability entities.

Recommendation – G11

Communicate and coordinate with neighboring systems for reassessing and re-posturing a system following an event that places the system in an insecure or unstudied state following an event that places the system in an insecure or unstudied state.

Recommendations for Operating Guidelines

RTBPTF recommends that an operating guideline be developed in support of the new requirements recommended above for reassessing and re-posturing the electric system. At a minimum, the following tasks, functions, and other actions should be included in the recommended policies and procedures:

- Communication and coordination with neighboring systems
- Verification of situational awareness
- Conservative operations (discussed in Section 3.3, Conservative Operations, of this report)
- Verification of data availability
- Verification of tool availability
- Reassessment, recalculation, or reverification of SOLs
- Reassessment, recalculation, or reverification of IROLs
- Identification of appropriate control actions or specific methodologies for developing appropriate control actions

Alternatively, this operating guideline may be incorporated in the revised standards recommended above if the standard-drafting team and industry deem that inclusion appropriate.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for system reassessment and re-posturing.

Examples of Excellence

RTBPTF cites the development of documented guidelines to address events on the transmission system that are outside the scope of established operations by the Virginia Carolinas (VACAR) South Subregion of SERC Reliability Corporation (SERC) as an example of excellence (See EOE-16 in Appendix E). These guidelines, which are part of the *VACAR-South Reliability Coordinator Handbook*, are intended for use by the RC working in close coordination with the BAs (TOPs) within the reliability area, and includes several examples of what to include in a procedure for reassessing and re-posturing the system following an event or events that leave the system in an insecure or unstudied state.

Section 3.7
Blackstart Capability

Definition

Blackstart generators can operate without an external power source. They are designed to provide power to critical transmission pathways after a blackout so that other critical generators can be restarted. Operating practices related to blackstart capability define how a system operator maintains awareness of and responds to the condition of blackstart generating units and transmission paths identified in the system restoration plan as being essential for restoring power after a blackout.

Background

The *Outage Task Force Final Blackout Report* states that, "to deal with a system emergency that results in a blackout,…there must be procedures and capabilities to use 'black-start' generators (capable of restarting with no external power source) and to coordinate operations in order to restore the system as quickly as possible to a normal and reliable condition."[29] NERC Reliability Standard EOP-005-0, System Restoration Plans, requires each TOP to have a plan for re-establishing its electric system in the event of a partial or total shutdown. Among other things, restoration plans must evaluate the reliable capability of blackstart generation resources and the "cranking" transmission paths needed to deliver those resources to other generating units, which will be started subsequently in accordance with the restoration plan. Most of the requirements of this standard concern long-term activities such as annual review and update of the plan, periodic testing, and annual simulation.

The standard contains a requirement (R8) that each TOP shall "ensure the availability and location of blackstart capability within its area to meet the needs of the restoration plan." Although this requirement does not specify the time frame to which it applies, an argument can be made that it must apply to near-term or real-time awareness of the condition of blackstart facilities. It stands to reason that, once having identified blackstart generation resources and key transmission paths, TOPs must not inadvertently compromise their ability to implement system restoration plans by neglecting to maintain day-ahead, current-day, or real-time awareness of the condition of the blackstart facilities.

The practices examined here are not to be confused with practices required by NERC Reliability Standard EOP-005-0, System Restoration Plans. These NERC practices generally concern long-term activities such as periodic testing of blackstart units and periodic system restoration drills. The practices addressed in this section pertain to near-term or real-time awareness of the state, availability, and capability of a system's blackstart facilities.

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[29] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April. p.10.

The blackstart capability section of the Real-Time Tools Survey addresses the prevalence of and methods for documenting and monitoring real-time blackstart conditions and responding to a lessening or loss of blackstart capability.

Summary of Findings

Survey respondents generally have documented practices regarding blackstart capability, but it is clear from the survey results that more specific guidance and requirements are needed in this area.

Documentation of Monitoring Practices

Survey responses reveal that industry members generally possess documented practices for maintaining awareness of blackstart capability. Approximately 63 percent of respondents (27 out of 43) report having documented practices for maintaining awareness of blackstart capability. This figure includes 75 percent (12 out of 16) of RCs who responded. More than 80 percent (23 out of 27) of those who have documented practices consider them “essential” for situational awareness. This figure includes 69 percent (11 out of 16) of the responding RCs.

All (27 out of 27) those with documented practices have them in the form of published procedures. Table 3.7-1 identifies the types of documentation that respondents maintain monitoring blackstart capability.

Documentation of Procedures for Monitoring Blackstart Capabilities	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	RC16	Others	Total
Published procedures	X	X	X	X	X	X	X	X	X	X	X	X					15	**29**
Web-based help systems	X	X	X	X				X									1	**6**
Departmental memos	X	X				X											7	**10**
EMS display notes (e.g., one-line notes)					X		x										3	**5**
Online help systems (EMS)			X														2	**3**

Table 3.7-1 — Documentation of Procedures for Monitoring Blackstart Capabilities[30]

Information Monitored

The survey inquired about the specific information that operators monitor in order to maintain awareness of current blackstart capabilities. Table 3.7-2 summarizes the responses. All but 2 of the respondents included in the "Others" column of the table represent TOPs. The responses summarized in this column indicate that TOPs monitor a wide variety of information, as do many RCs who are also TOPs. It may be that TOPs monitor such a wide range of information because, in most cases, only the TOP has direct responsibility for and control over a system restoration plan that utilizes blackstart generation to energize key transmission paths. Several RCs report monitoring a narrower scope of information, and others did not respond to this question.

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[30] Reliability coordinator responses are indicated with "X." Aliases are used as column headers to mask the RCs' names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, "RC 1" in any given table is not the same as "RC 1" or the equivalent identifier in another table in this report.

Blackstart Information Monitored	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	Others	Total
On-line/off-line status of blackstart units	X	X	X	X	X	X	X	X	X	X	X					20	**31**
Scheduled return-to-service dates for outaged blackstart units	X	X	X	X	X	X	X	X	X	X						16	**26**
Derated capacity of blackstart units	X	X	X		X	X	X	X	X	X						12	**21**
Status of transmission lines on alternative pathways	X	X	X	X	X		X	X	X	X						16	**25**
Scheduled return-to-service dates for outaged transmission lines in critical system restoration paths	X	X	X	X	X	X	X		X							15	**23**
Status of SCADA communication links to blackstart units and switchyards	X	X	X	X				X		X						15	**21**
AVR status of blackstart units	X	X	X		X											9	**13**
Fuel availability for blackstart units	X	X		X		X										10	**14**
Status of remote/local control switches for blackstart units	X	X														14	**16**

Table 3.7-2 — Blackstart Information Monitored

Actions to be Taken

The survey inquired about what documented actions system operators are expected to take when blackstart capability is found to be inadequate, i.e., when a blackstart generator or key transmission path identified in the system restoration plan becomes unavailable or unusable. Table 3.7-3 summarizes the responses. Fewer respondents identify expected actions than report having documented practices for awareness of blackstart capability. The difference in number of respondents might indicate that some documented practices pertain more to long-term capability than to current conditions.

In addition to the expected operator actions listed in Table 3.7-3, one RC respondent comments that the RC's outage coordinators "make sure that multiple adjacent black-start units are not planned out at the same time." Others who responded to this section of the survey did not specifically state that the RC makes a concerted effort to avoid compromising system restoration plans when reviewing and approving planned outages. Table 3.7-3 shows that there is a range of expected responses to a loss of blackstart capability, rather than a consistent, uniform set of responses.

Documented Actions for Inadequate Blackstart Capabilities	RC1	RC2	RC3	RC4	RC5	RC6	RC7	RC8	RC9	RC10	RC11	RC12	RC13	RC14	RC15	Others	Total
Notify management	X	X	X	X		X			X	X						13	**20**
Expedite current outages	X	X	X	X	X		X	X								8	**15**
Reschedule planned outages	X	X	X		X		X	X								9	**15**
Request engineering studies for additional options	X	X	X	X		X			X							14	**20**
Notify other entities (e.g., RCs, nuclear stations)	X	X	X		X	X										12	**17**

Table 3.7-3 — Documented Actions for Inadequate Blackstart Capability

Recommendations for New Reliability Standards

The *Outage Task Force Final Blackout Report* states that the NERC Reliability Standards are based on seven key concepts, one of which is emergency preparedness.[31] In the context of emergency preparedness, the report emphasizes the need for "procedures and capabilities to use 'black start' generators (capable of restarting with no external power source) and to coordinate operations in order to restore the system as quickly as possible to a normal and reliable condition."[32]

For the most part, the necessary "procedures and capabilities" are addressed in the EOP series of standards, in particular, NERC Reliability Standard EOP-005-0, System Restoration Plans. Although most of the requirements of this standard apply to long-term issues such as annual review and update of the plans, the standard contains a requirement (R8) that each TOP shall "ensure the availability and location of black-start capability within its area to meet the needs of the restoration plan." Although this requirement does not specify the time frame to which it applies, an argument can be made that it must apply to the near-term or real-time situational awareness of the availability and capability of blackstart facilities.

Although NERC Reliability Standard EOP-005-0, System Restoration Plans, requires each TOP to "ensure the availability and location of black-start capability within its area to meet the needs of the restoration plan," currently each TOP decides how to accomplish this goal.

Based on survey results, RTBPTF recommends that requirement R8 of NERC Standard-EOP-005-0 be revised to specify that operators receive the information they need to maintain situational awareness of the availability and capability of the blackstart generation and transmission resources identified in their system restoration plans. The task force also recommends that requirement R8 specify that operators be provided

[31] Outage Task Force Final Blackout Report, Pages 6–10.
[32] Ibid. Page 10.

documented practices and procedures that identify the information they should monitor to ensure adequate blackstart resources and the actions they should take if blackstart conditions are less than described in the restoration plan. The task force recommends that an operating guideline be developed to support the expanded requirement R8.

RTBPTF also recommends that NERC Standard-TOP-003-0, Planned Outage Coordination, be revised to include a requirement that scheduled outages of blackstart generation resources be coordinated so that key elements of the system restoration plan are not compromised without adequate alternative resources being available.

Recommendation – S35

Provide information to operators to maintain awareness of the availability and capability of the blackstart generators and transmission restoration paths.

RTBPTF Recommendation

RTBPTF recommends that requirement R8 of NERC Standard-EOP-005-0, System Restoration Plans, be revised to address operator awareness of the availability of blackstart resources, as follows:

PR1. Each transmission operator shall provide its operators with the information necessary to maintain awareness, in real time and on a current-day and day-ahead basis, of the availability and capability of the blackstart generation resources and transmission cranking paths identified in the system restoration plan. In addition, operators shall be provided documented practices and procedures that specify the information to be monitored to ascertain the availability and capability of blackstart resources and that identify the actions to be taken if blackstart availability or capability is less than that described in the restoration plan.

RTBPTF developed the following proposed measure (PM) for the proposed requirement above:

PM1. Each transmission operator shall demonstrate the documented practices and procedures that specify the information to be monitored to ascertain the availability and capability of blackstart resources and that identify the actions to be taken if blackstart availability or capability is less than that described in the restoration plan. In addition, each transmission operator shall demonstrate the user interface for visual presentation of the necessary information.

Recommendation – S36

Plan and coordinate scheduled outages of blackstart generators and transmission restoration paths.

RTBPTF also recommends that a requirement be added to Standard-TOP-003-0 to address scheduled outages of blackstart generation resources and/or key transmission restoration pathways.

PR2. Each reliability coordinator, transmission operator, balancing authority, and generator operator shall plan and coordinate scheduled outages of blackstart generation resources and/or key transmission restoration pathways so that the reliable capability of key elements of the system's restoration plans is not compromised without adequate redundant or alternative resources or plans being identified and available.

RTBPTF developed the following proposed measure for PR2:

PM2. Each reliability coordinator, transmission operator, balancing authority, and generator operator shall show evidence that the viability of the transmission owner's restoration plan is reaffirmed on a daily basis.

Rationale

The *Outage Task Force Final Blackout Report* reiterates the importance of having "procedures and capabilities" related to the blackstart resources needed to restore a transmission system following events such as the August 14, 2003, blackout. Reliability standards that address such procedures and capabilities currently focus on long-term issues such as verifying the capabilities of blackstart resources and updating blackstart procedures. The above recommendations will increase the scope and specificity of reliability standards to give operators the information and guidance they need to maintain situational awareness of the status, availability, and capability of blackstart resources and the viability of blackstart procedures in all time frames, up to and including real time. The findings of the Real-Time Tools Survey establish that documented procedures for maintaining situational awareness of blackstart capability are prevalent within the industry. The PRs and PMs presented above will establish formal, uniform requirements for documented and demonstrable procedures that will raise the bar for many reliability entities.

Recommendation – G12

Monitor and ensure operator awareness of current conditions of blackstart generators and status of transmission restoration paths.

Recommendations for Operating Guidelines

As discussed previously, every TOP is currently required to "ensure the availability and location of blackstart capability within its area to meet the needs of the restoration plan." Each TOP decides how to achieve this goal. Many survey respondents report that their system operators monitor a variety of information to maintain awareness of blackstart capability. Current practices provide a good guideline for others to follow in providing for the availability of blackstart resources.

RTBPTF recommends that an operating guideline be developed in support of requirement R8 of NERC Standard EOP-005-0, System Restoration Plans. The guideline should specify that system operators monitor the following information to maintain awareness of the current condition of blackstart resources:

- On-line/off-line status of blackstart generating units
- Scheduled return-to-service dates for outaged blackstart units
- Derated blackstart unit capacity
- Status of transmission lines along critical pathways for system restoration
- Scheduled return-to-service dates for outaged transmission lines along critical pathways for system restoration
- Status of transmission lines in alternative restoration pathways
- AVR status of blackstart units
- Fuel availability for blackstart units

The task force recommends that visualization techniques for efficiently and effectively providing system operators with information regarding blackstart capability, as listed in the operating guidelines recommended above, be developed by EMS vendors, EMS user groups, and the various forums available for the exchange of ideas among operators.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for blackstart capability.

Examples of Excellence

RTBPTF identified no examples of excellence related to blackstart capability.

Section 4.0
Power System Models

Introduction

An accurate real-time model is essential for assessing the reliability of the electric system. Real-time models that are too small, too large, too highly equivalenced, or inadequately maintained and updated can cause significant problems for entities that oversee reliability. A consistent, uniform set of modeling and data exchange practices, procedures, and standards will greatly facilitate the creation and subsequent maintenance of optimal models. The sections that follow summarize and analyze the model characteristics and modeling practices reported by respondents to the NERC Real-time Tools Survey. The analysis attempts to quantify some of the key characteristics of the respondents' network models and identifies modeling areas that need more analysis, from which recommendations for new reliability standards or guidelines may be forthcoming.

The fundamental responsibility of RCs, TOPs, and other entities that oversee grid reliability is to assure that the transmission system can be quickly restored to a secure state following any single contingency. The real-time tools that are necessary to assess the condition of the transmission system, such as the state estimator and contingency analysis, cannot function without a real-time model of the system. A real-time model is a high-fidelity representation of:

1) transmission and generation facilities within the area of responsibility of the reliability entity (the *internal network model*) and
2) facilities adjacent to and beyond the area of responsibility (the *external network model*) that can significantly impact voltage and flows within the area of responsibility or that provide a path for flows into or out of external facilities that can impact the area of responsibility.

Even the best-designed tools, no matter how advanced, can be severely compromised by inaccuracies and omissions in the network models on which they rely. Unfortunately, entities implementing network analysis applications for the first time often focus on the applications themselves and underestimate the cost, effort, and level of expertise required to build and maintain an adequate real-time network model.

Determining which facilities to represent in the internal network model is relatively straightforward. Typically, the internal model includes all bulk electric system facilities within the area of responsibility. Determining which facilities to represent in the external model is much more complex. There is no "bright line" that identifies external areas whose operations can impact the area of responsibility. Real-time modelers use a variety of criteria, analytical techniques, engineering judgment, and other methods to determine what to include and exclude in their external models. Although some variation in external models among regions is justified based upon the size and geographic location of a particular entity's area of responsibility, inconsistencies in identifying the relevant external facilities can lead to external models that are too small, too large, or too highly "equivalenced." In an equivalenced model, individual physical electrical elements are represented by a reduced set of non-physical elements that mimic the same electrical response as the individual elements. For example, multiple generating units may be represented by a single large generator that has the same total output, or a double-circuit line may be represented by a single-circuit line with the same effective impedance.

External models that are too small, too large, or too highly equivalenced each have characteristics that can negatively affect the quality of the results of the real-time network analysis tools that use them (and therefore the ability of reliability entities to do their jobs well).

External models that are too small may not include enough external transmission elements to accurately represent loop flows through external systems that can significantly impact internal facilities. In some cases, loop flows may not be represented at all or may be allocated in whole or in part to facilities in the external model over which they do not actually flow. A state estimator can often overcome this challenge in determining the actual flows and voltages on the internal facilities because it uses "best fit" algorithms (e.g., weighted least-squares methods) to estimate the current system state. However, contingency analysis cannot accurately calculate post-contingency flows on internal facilities if the branches that carry these flows are not accurately represented in nearby external facilities. The analysis may produce a solution that inaccurately suggests the system is secure when it is not, or the reverse. Similar problems can result when a model omits external facilities that would individually or collectively contribute to significant loading on internal facilities if those external facilities were out of service.

External models that are too large require more resources to maintain than they would otherwise. Reliability entities typically underestimate the resources required to build and maintain a real-time model and often do not have enough staff to keep up with both a detailed internal model and all the significant changes made to the external facilities included in a large, detailed external model. In addition, processes for notification of grid changes and exchange of relevant modeling data among reliability entities are minimal or even nonexistent in some regions. The result is that large, detailed models can gradually become inaccurate and obsolete over time. The state estimator may be able to overcome this challenge in determining the actual flows and voltages on internal facilities, but contingency analysis will not accurately calculate post-contingency flows and voltages on internal facilities if the representations of nearby external facilities are not correct. A large external model also causes network applications to use significant additional computer resources (memory, CPU cycles, discs, etc.), and these applications will take longer to solve. Consequently, the reliability entity may run state estimation, contingency analysis, and other network analysis applications less frequently.

External models that are highly equivalenced pose similar problems. A decision to represent a particular external facility as part of a fictitious "equivalent" element is usually based on a determination that the facility by itself does not have a significant impact on internal facilities but needs to be represented along with other similar facilities to provide a path for external flows into or out of facilities that are explicitly modeled. A problem occurs when a facility that has been incorporated into one or more equivalent elements has been upgraded in the field to the extent that it now needs to be modeled explicitly (e.g., from 115 kV to 230 kV). In most cases it is extremely difficult to deconstruct equivalenced elements into their constituent facilities for the purpose of remodeling one of them explicitly. The only sure way is to use equivalencing tools to recompute new external equivalent elements that are based on the new explicitly modeled facilities. This is a tedious, time-consuming task. For this reason, facility upgrades are often not incorporated into an equivalenced model. As above, the state estimator may be able to overcome this challenge in determining actual flows and voltages on the internal facilities, but contingency analysis will not be able to accurately reflect post-contingency flows on internal facilities if the representations of nearby external facilities are no longer correct.

Any external model that has not been sufficiently maintained can cause solution problems for the state estimator as well as contingency analysis and other applications that use the state estimator base case. The state estimator may have difficulty converging or fail to converge if the external model is outdated. In some cases, errors caused by poor external model fidelity can be "smeared" into internal facilities in the state estimator solution, causing inaccurate estimates for tie lines and other nearby internal facilities. Solution accuracy and convergence problems can impact contingency analysis similarly. When the state estimator fails to converge, real-time contingency analysis is effectively disabled. And even when the state estimator obtains a solution, a poor external model can cause contingency analysis to have convergence problems and/or yield erroneous solutions.

Good practice dictates that all relevant external electrical components, along with their associated real-time analog readings and circuit breaker and/or switch statuses, be modeled explicitly. Maintenance of accurate wide-area models requires continual exchange of system modeling data as well as exchange of real-time or near-real-time data with neighboring utilities. This exchange is required to support pertinent "instantaneous" metering and status information via SCADA/ICCP or other data links.

A consistent, uniform set of modeling and data-exchange practices, procedures, guidelines and/or standards facilitate the creation and subsequent maintenance of network models. RCs, TOPs, and all other entities responsible for reliability must have confidence that their neighbors are doing a competent job in assessing reliability and thereby protecting one another from harm. Real-time models are the foundation for these assessments. Therefore, all reliability entities have a vested interest in the quality and accuracy of their neighbors' real-time models.

RTBPTF recommends further analysis in the areas of model data exchange and grid change notification procedures, external model development guidelines, and the eventual use of CIM XML[1] for model exchange.

Significance to the August 14, 2003 Blackout

RTBPTF investigated the use of modeling data throughout the industry because the lack of real-time telemetry data in the external model was one of the contributing factors to the August 2003 blackout. MISO was using a static bus-branch network model in parts of its external model. When the Stewart-Atlanta 345-kV line tripped (monitored by the PJM RC), MISO's state estimator did not know that the line had gone out of service. This led to a data mismatch that prevented MISO's state estimator from computing a solution that could be used by its real-time contingency analysis application. Without real-time contingency analysis, MISO's ability to see that its system was in danger was greatly compromised.

Recommendations for New Reliability Standards

The Real-Time Tools Survey reveals that entities have significantly different practices for creating and maintaining models of the bulk electric system. Therefore, RTBPTF did not make any recommendations for the creation of new reliability standards pertaining to model practices. However, RTBPTF does identify several areas that require additional analysis to improve the state of modeling within the industry. The items that will require additional analysis include providing clarity to some fundamental definitions, identifying methods for grid change notification and model data exchange, developing external models, and implementing a CIM XML model exchange.

[1] The term "CIM XML" in this report refers to the language used for power system model exchange that conforms to the NERC common power system model (CPSM) specifications. "CIM" is the "Common Information Model" definition used to represent the power system. XML (extensible mark-up language") is an industry standard syntax used in the model data files.

Section 4.1
Model Characteristics

Definition

The majority of real-time applications used to monitor and study the health of the transmission grid require an electrical model of the interconnection, which is commonly referred to as the "network model." The network model has two components: the "internal model" and the "external model." The internal model represents the portion of the transmission grid for which the reliability entity is responsible (i.e., the electrical footprint of an RC or TOP). The external model represents the electric grid that surrounds an entity's primary area of responsibility.

Background

In general, the internal network model contains significantly more detail than the external model in terms of both voltage levels and the types of equipment represented. The external model also often contains "equivalent" elements. An equivalent element is a fictitious (non-physical) element that represents two or more physical elements (e.g., a single "generator" that represents multiple generators, a single "line" that represents multiple lines, etc.). Equivalent elements provide the same electrical response as the elements they replace in the model. They are generally employed on the outer edges and/or within lower-voltage levels of the model where physical representation is not critical.

Summary of Findings

The questions in the model characteristics section of the NERC Real-time Tools Survey were designed to capture essential characteristics of the respondents' internal and external network models. The information collected in this section of the survey also provides insight into the respondents' network modeling practices.

The data collected in this section of the survey are primarily related to the respondents' network model dimensions and modeling practices. This information is intended to provide context and support for information collected in other sections of the survey. The analysis of findings below is organized into the following modeling categories:

- general model size and detail
- future modeling plans
- applications that use the network model
- circuit breaker and switch modeling
- generator step-up transformer modeling

- generator auxiliary load modeling
- generating unit Mvar capability curve modeling
- verifying transmission-line characteristics
- transmission line real-time limits
- transformer real-time limits
- bus load modeling
- external network models

Some of the key survey findings are listed below:

- Survey respondents' network models vary widely in terms of size, as one would expect. However they also vary widely in modeling detail (in terms of switches and elementary bus nodes per station); internal-to-total bus ratios, internal-to-total branch ratios; analog and status measurement density; and other dimensions that are normalized by buses, stations, and other basic model dimensions. This wide variation was seen in responses from both RCs and non-RCs.

- A large number of respondents plan major changes in their network models that are "above and beyond routine model changes" in the coming year, particularly in their external models.

- An overwhelming majority of respondents consider the state estimator, real-time contingency analysis, study contingency analysis, and on-line power flow to be the most important applications that rely on the network model. Other network applications such as operator OPF, Volt-var dispatch, etc. were cited to a much lesser extent.

- Higher-voltage portions of respondents' power systems are modeled in more detail (in terms of power breakers and switches) than the lower-voltage portions of their systems. Also, circuit breaker devices are modeled more than switches (i.e., gangs, disconnects, etc.)

- An overwhelming majority of respondents model at least some generator step-up transformers, generator auxiliary loads, and generating unit Mvar capability curves in their internal network models. This is typically done for the larger generating units. Surprisingly, not all RCs model generating unit Mvar capability curves despite the importance of these curves for determining Mvar reserves.

- Half or fewer of survey respondents verify the electrical characteristics of their transmission lines.

- More than 75 percent of all survey respondents, including 90 percent of RCs, report that their network models support the use of real-time limits and/or multiple limit sets based on temperatures or seasons for lines and transformers. Of those respondents whose models support this feature, almost 90 percent are using it for lines, and about 75 percent are using it for transformers.

- The majority of respondents use multiple methods to determine the elements to include in their external models (e.g., off-line modeling utilities, system planning studies, etc.). Surprisingly, more than one-third of the RCs use "engineering judgment" as the sole means of determining what elements to include in their external models.

- CIM XML[2] is not currently used to a wide extent for model maintenance.

- Virtually all of the respondents have at least some real-time analog and/or status telemetry linked to their external network models. However the real-time analog/status point measurement density in the external models, in terms of measurements per station, varies widely. (Note: The lack of real-time telemetry data in the external model was one of the contributing factors in the August 2003 blackout).

The information in the subsections below is based upon an analysis of the data submitted by survey respondents. Note that because of the length of the survey and the volume of data involved, RTBPTF was not able to filter all of the responses for inconsistencies, omissions, and suspect data entries, or to follow up with each of the respondents.

General Model Size and Detail

The survey collected information on the size and detail of each respondent's network model. The data collected included basic network model dimensions such as numbers of buses, lines, breakers, switches, transformers, and other system elements. Network model size is commonly expressed in terms of buses and branches.[3] Table 4.1-1 and Table 4.1-2 show the numbers of model buses and branches reported by survey respondents.[4]

From Table 4.1-1 we see that the network models used by RCs vary widely in size from 687 buses to more than 30,000 buses. From Table 4.1-2 we see that the models used by all other respondents (e.g., TOPs and BAs) also vary widely

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[2] The term "CIM XML" in this report refers to the language used for power system model exchange that conforms to the NERC common power system model (CPSM) specifications. "CIM" is the "Common Information Model" definition used to represent the power system. XML (extensible mark-up language") is an industry standard syntax used in the model data files.
[3] A "branch" in this context includes lines (real or equivalent), transformers (of any type), "zero impedance" branches, and series capacitors/reactors.
[4] The identities of the respondents in this and other sections of this report have been masked. The identifiers used for each respondent change in each table and figure. That is, respondent "RC01" in one figure or table is not necessarily the same respondent as "RC01" in a different figure or table.

in size from 14 buses to more than 24,000 buses. The charts in Figure 4.1-1 and Figure 4.1-2 graphically illustrate this. Both RCs and the other respondents exhibit similar wide variations in the number of model branches.

The size of each survey respondent's external model relative to the total model size also varies widely. This variation is clearly illustrated by the differences in the respondents' external bus to total bus ratios, as can be seen in Table 4.1-1 and Table 4.1-2 (see also Figure 4.1-3 and Figure 4.1-4). A similar variation is also seen in the external-branch-to-total-branch ratios. RCs report external-bus-to-total-bus model ratios that ranged from less than one percent to almost 81 percent while all other respondents report ratios that varied between seven and 67 percent. Similarly, RCs report external-branch-to-total-branch ratios that range from less than one percent to 82 percent. The other respondents had external-branch-to-total-branch ratios that range from less than one percent to 94 percent.

Some of the wide variation in external model sizes can be explained by a respondent's geographic location within an interconnection. For instance, a system in Florida with interconnection ties only to the north would likely require a smaller external model than a system in Ohio with ties to the interconnection on all sides. However, much of this variation is also due to the diversity of modeling approaches and philosophies used to determine how large an external model is required to support network applications. This topic is addressed in greater detail in Section 4.2, Modeling Practices and Tools, of this report.

Resp[5]	Internal Buses	External Buses	Total Buses	Internal Branches	External Branches	Total Branches	External Bus to Total Bus Ratio	External Branch to Total Branch Ratio
RC01	12,834	17,873	30,707	17,348	24,516	41,864	0.58	0.59
RC02	7,624	4,837	12,461	9,891	8,548	18,439	0.39	0.46
RC03	4,330	6,239	10,569	5,673	9,633	15,305	0.59	0.63
RC04	3,750	3,420	7,170	4,643	6,654	11,297	0.48	0.59
RC05	1,334	5,580	6,914	1,610	7,146	8,756	0.81	0.82
RC06			5431			3,862		
RC07	5,157	9	5,166	6,455	7	6,462	0.002	0.001
RC08	2,166	1,577	4,564	3,485	4,025	7,510	0.35	0.54
RC09	2,507	1,575	4,082	1,751	5,479	7,230	0.39	0.76
RC10	3,251	638	3,889	3,891	1,165	5,056	0.16	0.23
RC11			3,674			4,935		
RC12	3,300	300	3,600	2,206	182	2,388	0.08	0.08
RC13	1,923	1,506	3,429	2,380	2,216	4,596	0.44	0.48
RC14	1,770	463	2,233	2,561	630	3,191	0.21	0.20
RC15	1,287	445	1,732	1,822	776	2,598	0.26	0.30
RC16	1,110	60	1,270	1,053	41	1,094	0.05	0.04
RC17	672	15	687	767	19	786	0.02	0.02
Count	15	15	17	15	15	17	15	15
Average	3,534	2,969	6,328	4,369	4,736	8,551	0.32	0.38
Median	2,507	1,506	4,082	2,561	2,216	5,056	0.35	0.46
Std Dev	3,154	4,633	7,006	4,334	6,433	9,839	0.24	0.28
Max	12,834	17,873	30,707	17,348	24,516	41,864	0.81	0.82
Min	672	9	687	767	7	786	0.002	0.001

Table 4.1-1 — Bus and Branch Count for RC Respondents[6]

[5] Aliases are used to mask RCs' names. The aliases in this table are not necessarily consistent with those used in similar tables in this report. That is, "RC 01" in any given table is not the same as "RC 1" or the equivalent identifier in another table in this report.

[6] Some computed quantities are blank for entities that did not provide an internal/external breakdown of their buses and branches.

Resp	Internal Buses	External Buses	Total Buses	Internal Branches	External Branches	Total Branches	External to Total Bus Ratio	External to Total Branch Ratio
R01	8,087	16,138	24,225	8,389	22,783	31,173	0.67	0.73
R02	7,014	1,073	8,087	7,120	1,269	8,389	0.13	0.15
R03	900	7,100	8,000	681	10,674	11,355	0.89	0.94
R04	2,751	2,190	4,941	3,470	2,567	5,082	0.44	0.51
R05	1,589	2,505	4,094	1,770	4,628	6,398	0.61	0.72
R06	600	3,090	3,690	857	5,492	6,349	0.84	0.87
R07	973	1,952	2,925	1,190	3,509	4,699	0.67	0.75
R08	761	2,135	2,896	887	3,252	4,139	0.74	0.79
R09	1,838	504	2,342	2,215	544	2,759	0.22	0.20
R10	382	1,906	2,288	504	3,428	3,932	0.83	0.87
R11	468	1,722	2,190	550	2,912	3,462	0.79	0.84
R12	1,482	657	2,139	1,799	1,032	2,831	0.31	0.36
R13	630	1,150	1,780			2,889	0.65	
R14	282	1,298	1,580	593	3,066	3,659	0.82	0.84
R15	581	929	1,510			1,979	0.62	
R16	1,070	167	1,237	2,038	428	2,466	0.14	0.17
R17	1,058	10	1,058	1,389	7	1,396	0.01	0.01
R18	170	630	800	651	2,109	2,760	0.79	0.76
R19	180	420	600	125	546	671	0.70	0.81
R20	450	40	490	570	20	590	0.08	0.03
R21	208	2	210	296	2	298	0.01	0.01
R22	50	10	60	159	10	169	0.17	0.06
R23	13	1	14	22	4	26	0.07	0.15
Count	23	23	23	21	21	23	23	21
Average	1,371	1,984	3,355	1,680	3,252	4,673	0.49	0.50
Median	630	1,073	2,139	857	2,109	2,889	0.62	0.72
Std Dev	2,061	3,452	5,050	2,195	5,146	6,398	0.31	0.35
Max	8,087	16,138	24,225	8,389	22,783	31,173	0.89	0.94
Min	13	1	14	22	2	26	0.009	0.005

Table 4.1-2 — Model Bus and Branch Count for Other (non-RC) Respondents[7]

[7] Some computed quantities are blank for entities that did not provide an internal/external breakdown of their buses and branches.

Network Model Bus Counts for RCs

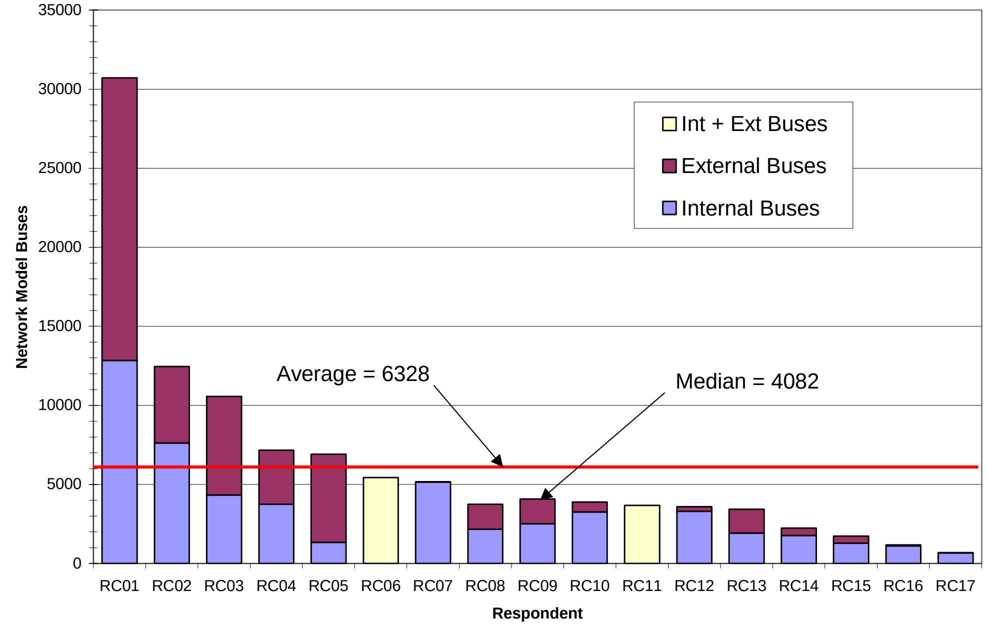

Figure 4.1-1

Network Model Bus Counts for Other (non-RC) Respondents

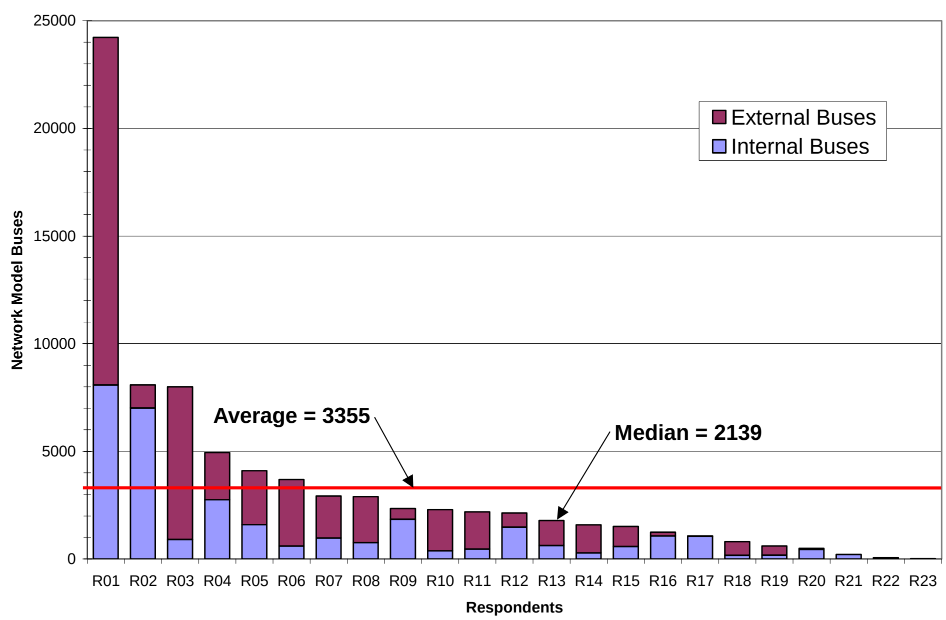

Figure 4.1-2

External Bus to Total Bus Ratios for RCs

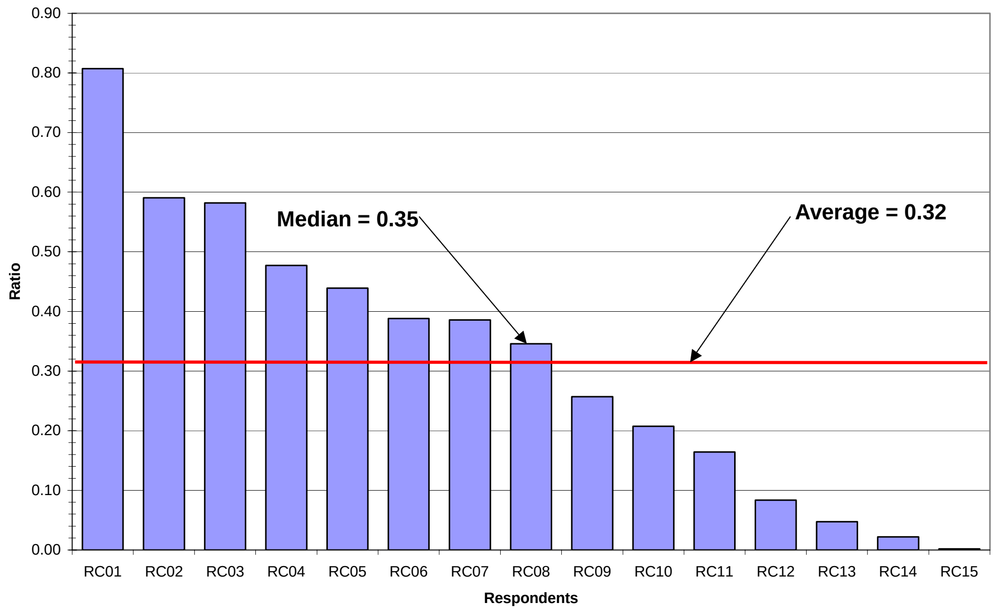

Figure 4.1-3

External Bus to Total Bus Ratios for Other (Non-RCs) Respondents

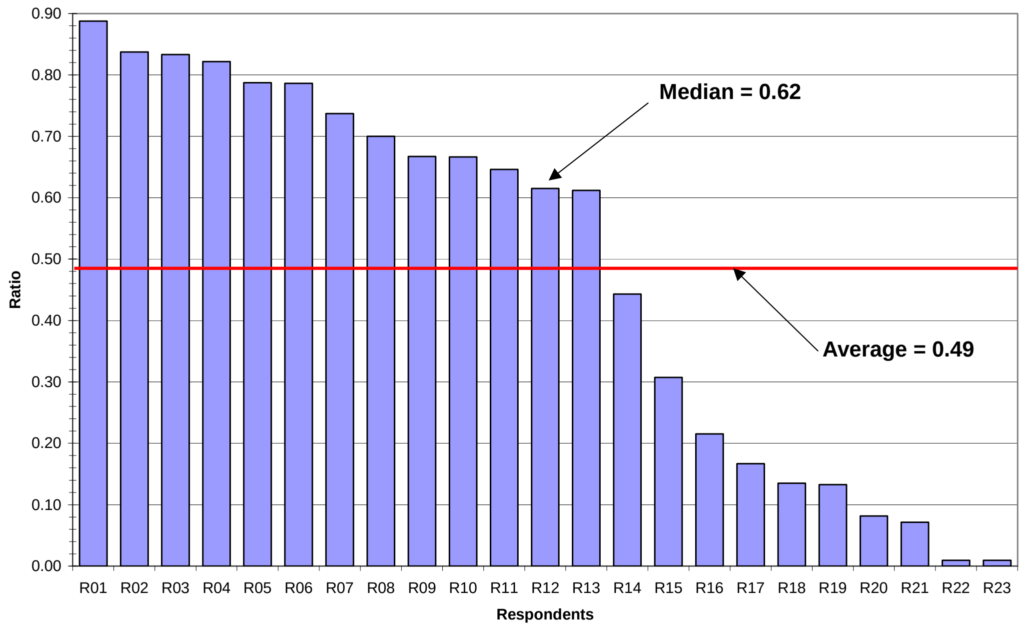

Figure 4.1-4

Approximate measures for quantifying model detail were computed to compare the level of detail in respondents' models. The two measures that were used were:

- Breakers and switches per station ratio
- Elementary bus nodes per electrical bus ratio

These are very rough measures that are affected by many transmission system specific characteristics. However they provide a good approximation of modeling detail in most cases. In general, a more detailed model (in terms of equipment and voltage levels modeled) will contain larger numbers of breakers and switches per station than one with less detail. The same is true for the node-to-bus ratio because modeling additional equipment generally requires that the model use more nodes. In the extreme case of a planning model (i.e., a bus-branch model), the breakers and switches per station ratio for is zero. The node-to-bus ratio for a planning model is one.

Table 4.1-3 and Table 4.1-4 show the number of stations, breaker-and-switch totals, and the breakers-and-switches-to-station ratios for the RCs and other respondents. Table 4.1-5 and Table 4.1-6 show the number of buses, elementary bus nodes, and the elementary-bus-nodes-per-bus ratios for the RCs and other respondents. In each of these tables, the raw data and computed ratios are shown for the internal model, the external model, and total model.

From Table 4.1-3 and Table 4.1-4, we see that the breakers-and-switches-per-station ratios vary widely among respondents. This is true for both the RCs and other respondents. We also see that the computed ratio is larger for the internal model than it is for the external model for most respondents. In many of the cases where the external ratio is large, it seems to be because the external model is very small relative to the total model. The average and median ratios for the internal models are significantly larger than those for the external models, as one might expect.

From Table 4.1-5 and Table 4.1-6, we see that the elementary-bus-node-to-electrical-bus-node ratios also vary widely among respondents. The computed values of the node-to-bus ratios vary the same way that the breakers-and switches-per-station ratio varies. That is, there is wide variation for both the RCs and other respondents. Also, the ratio for the internal model is larger than it is for the external model in most cases. As with the breaker-and-switch-per-station ratios, the average and median node-to-bus ratios for the internal models are significantly larger than those for the external models.

One can conclude these ratios are generally larger for the internal models because they contain more breaker/switch detail than the external models. This is consistent with what one would expect. The large variation among respondents in the ratios can be explained, in part, by a number of factors related to the physical characteristics of the systems being modeled (e.g., the bus and breaker schemes used on the bulk electric system, etc.). However, another likely reason for this variation is differences in the respondents' modeling philosophies and practices. This will be illustrated later by some of the other survey responses that will be discussed.

Resp	Internal Stations	External Stations	Total Stations	Internal Breakers + Switches	External Breakers + Switches	Total Breakers + Switches	Int Breakers + Switches to Int Station Ratio	Ext Breakers + Switches to Ext Station Ratio	Total Breakers + Switches to Total Station Ratio
RC01	1,566	383	1,949	42,897	3,262	46,159	27.39	8.52	23.68
RC02	233	21	254	4,503	102	4,600	19.33	4.86	18.11
RC03	-----	-----	1,634	-----	-----	21,126	-----	-----	12.93
RC04	1,676	18	1,694	-----	-----	21,635	-----	-----	12.77
RC05	296	6	302	2,785	55	2,840	9.41	9.17	9.40
RC06	3,589	9	3,598	33,412	29	33,441	9.31	3.22	9.29
RC07	3,675	3,314	6,989	38,406	26,082	64,488	10.45	7.87	9.23
RC08	1,425	344	1,769	12,954	3,207	16,161	9.09	9.32	9.14
RC09	999	168	1,169	9,215	1,256	10,471	9.22	7.48	8.96
RC10	770	211	981	6,431	1,915	8,310	8.35	9.08	8.47
RC11	623	3,066	3,689	11,557	18,980	30,537	18.55	6.19	8.28
RC12	8,737	1,389	20,126	69,079	68,283	137,362	7.91	6.00	6.83
RC13	967	1,229	2,196	5,460	7,831	13,291	5.65	6.37	6.05
RC14	2,122	1,982	4,104	22,284	2,183	24,467	10.50	1.10	5.96
RC15	1,435	1,201	2,636	10,218	1,636	11,854	7.12	1.36	4.50
RC16	3,644	4,828	8,472	17,585	13,714	31,299	4.83	2.84	3.69
RC17	1,791	1,094	3,591	10,292	2,865	9,157	5.75	2.62	2.55
Count	16	16	17	15	15	17	15	15	17
Average	2,097	1,829	3,833	19,805	10,093	28,659	10.86	5.73	9.40
Median	1,501	739	2,196	11,557	2,865	21,126	9.22	6.19	8.96
Std Dev	2,094	2,925	4,737	18,558	17,861	32,219	6.17	2.90	5.24
Max	8,737	11,389	20,126	69,079	68,283	137,362	27.39	9.32	23.68
Min	233	6	254	2,785	29	2,840	4.83	1.10	2.55

Table 4.1-3 — Breakers and Switches per Station for RC Respondents

Resp	Internal Stations	External Stations	Total Stations	Internal Breakers + Switches	External Breakers + Switches	Total Breakers + Switches	Int Breakers + Switches to Int Station Ratio	Ext Breakers + Switches to Ext Station Ratio	Total Breakers + Switches to Total Station Ratio
R01	500	1,000	1,500	-----	-----	-----	-----	-----	-----
R02	-----	-----	-----	417	11	428	-----	-----	-----
R03	60	80	140	2,400	1,000	3,400	40.00	12.50	24.29
R04	120	2	122	-----	-----	1,433	-----	-----	11.75
R05	836	48	884	8,298	235	8,533	9.93	4.90	9.65
R06	1,756	1,471	3,227	12,833	12,149	29,829	7.31	8.26	9.24
R07	350	8	358	3,000	30	3,030	8.57	3.75	8.46
R08	580	4	584	4,700	170	4,870	8.10	42.50	8.34
R09	2,746	768	3,516	19,371	4,742	29,181	7.05	6.17	8.30
R10	100	280	380	1,160	1,200	2,360	11.60	4.29	6.21
R11	3,514	10,928	14,442	24,113	63,596	87,709	6.86	5.82	6.07
R12	800	301	1,101	6,407	57	6,464	8.01	0.19	5.87
R13	299	1,911	2,210	2,345	9,622	11,967	7.84	5.04	5.41
R14	50	10	60	275	15	290	5.50	1.50	4.83
R15	13	1	14	65	2	67	5.00	2.00	4.79
R16	282	1,298	1,580	1,416	5,484	6,900	5.02	4.22	4.37
R17	-----	-----	1,240	-----	-----	5,000	-----	-----	4.03
R18	578	1,718	2,296	5,633	1,566	7,199	9.75	0.91	3.14
R19	667	1,138	1,805	4,628	476	5,104	6.94	0.42	2.83
R20	600	3,090	3,690	4,600	1,600	6,200	7.67	0.52	1.68
R21	303	1,084	1,387	1,667	517	2,184	5.50	0.48	1.57
R22	437	5,556	5,993	2,292	2,809	5,101	5.24	0.51	0.85
R23	620	1,670	2,290	1,336	544	1,880	2.15	0.33	0.82
Count	21	21	22	20	20	22	19	19	21
Average	724	1,541	2,219	5,348	5,291	10,415	8.84	5.49	6.31
Median	500	1,000	1,444	2,700	772	5,051	7.31	3.75	5.41
Std Dev	895	2,524	3,102	6,446	14,130	19,000	7.84	9.54	5.13
Max	3,514	10,928	14,442	24,113	63,596	87,709	40.00	42.50	24.29
Min	13	1	14	65	2	67	2.15	0.19	0.82

Table 4.1-4 — Breakers and Switches per Station for Other (non-RC) Respondents

Resp	Internal Buses	External Buses	Total Buses	Internal Nodes	External Nodes	Total Nodes	Internal Node to Internal Bus Ratio	External Node to External Bus Ratio	Total Node to Bus Ratio
RC01	1,770	463	2,233	30,554	6,200	36,754	17.26	13.39	16.46
RC02	3,251	638	3,889	42,374	3,397	45,771	13.03	5.32	11.77
RC03	5,157	9	5,166	50,000	100	50,100	9.70	11.11	9.70
RC04	-----	-----	3,674	-----	-----	22,567	-----	-----	6.14
RC05	2,166	1,577	4,564	14,593	8,896	27,929	6.74	5.64	6.12
RC06	1,287	445	1,732	8,064	2,373	10,437	6.27	5.33	6.03
RC07	7,624	4,837	12,461	-----	-----	74,336	-----	-----	5.97
RC08	672	15	687	3,593	40	3,633	5.35	2.67	5.29
RC09	12,834	17,873	30,707	76,809	80,430	157,239	5.98	4.50	5.12
RC10	1,334	5,580	6,914	11,398	22,177	33,575	8.54	3.97	4.86
RC11	1,923	1,506	3,429	10,819	2,866	13,685	5.63	1.90	3.99
RC12	3,750	3,420	7,170	22,753	5,574	28,327	6.07	1.63	3.95
RC13	4,330	6,239	10,569	20,609	20,071	40,680	4.76	3.22	3.85
RC14	1,110	60	1,270	4,628	130	4,758	4.17	2.17	3.75
RC15	-----	-----	5,431	-----	-----	16,846	-----	-----	3.10
RC16	3,300	300	3,600	8,259	608	8,867	2.50	2.03	2.46
RC17	2,507	1,575	4,082	-----	-----	4,082	-----	-----	1.00
Count	15	15	17	13	13	17	13	13	17
Average	3,534	2,969	6,328	23,419	11,759	34,093	7.38	4.84	5.86
Median	2,507	1,506	4,082	14,593	3,397	27,929	6.07	3.97	5.12
Std Dev	3,154	4,633	7,006	21,542	21,872	37,107	3.98	3.60	3.73
Max	12,834	17,873	30,707	76,809	80,430	157,239	17.26	13.39	16.46
Min	672	9	687	3,593	40	3,633	2.50	1.63	1.00

Table 4.1-5 — Elementary Node-to-Bus Ratios for RC

Resp	Internal Buses	External Buses	Total Buses	Internal Nodes	External Nodes	Total Nodes	Internal Node to Internal Bus Ratio	External Node to External Bus Ratio	Total Node to Bus Ratio
R01	2,751	2,190	4,941	-----	-----	-----	-----	-----	-----
R02	1,482	657	2,139	-----	-----	-----	-----	-----	-----
R03	1,070	167	1,237	8,911	1,329	10,240	8.33	7.96	8.28
R04	170	630	800	1,000	5,000	6,000	5.88	7.94	7.50
R05	180	420	600	1,300	2,500	3,800	7.22	5.95	6.33
R06	973	1,952	2,925	5,816	12,624	18,440	5.98	6.47	6.30
R07	450	40	490	3,000	50	3,050	6.67	1.25	6.22
R08	382	1,906	2,288	2,000	12,227	14,227	5.24	6.42	6.22
R09	208	2	210	1,275	14	1,289	6.13	7.00	6.14
R10	468	1,722	2,190	2,028	10,998	13,026	4.33	6.39	5.95
R11	1,058	10	1,058	5,728	131	5,859	5.41	13.10	5.54
R12	630	1,150	1,780	5,000	3,000	8,000	7.94	2.61	4.49
R13	8,087	16,138	24,225	29,886	76,854	106,740	3.70	4.76	4.41
R14	581	929	1,510	-----	-----	6,638	-----	-----	4.40
R15	7,014	1,073	8,087	24,711	5,175	29,886	3.52	4.82	3.70
R16	1,838	504	2,342	7,447	572	8,019	4.05	1.13	3.42
R17	50	10	60	450	50	200	9.00	5.00	3.33
R18	1,589	2,505	4,094	6,921	3,768	10,689	4.36	1.50	2.61
R19	900	7,100	8,000	2,677	10,177	12,854	2.97	1.43	1.61
R20	761	2,135	2,896	2,001	2,641	4,642	2.63	1.24	1.60
R21	600	3,090	3,690	600	3,090	3,690	1.00	1.00	1.00
R22	282	1,298	1,580	282	1,298	1,580	1.00	1.00	1.00
R23	13	1	14	13	1	14	1.00	1.00	1.00
Count	23	23	23	20	20	21	20	20	21
Average	1,371	1,984	3,355	5,552	7,575	12,804	4.82	4.40	4.34
Median	630	1,073	2,139	2,353	2,821	6,638	4.80	4.79	4.41
Std Dev	2,061	3,452	5,050	7,930	16,849	22,634	2.40	3.31	2.25
Max	8,087	16,138	24,225	29,886	76,854	106,740	9.00	13.10	8.28
Min	13	1	14	13	1	14	1.00	1.00	1.00

Table 4.1-6 — Elementary Node-to-Bus Ratios for Other (non-RC) Respondents

Future Modeling Plans

The models used by network applications require continual maintenance to reflect changes that occur in the interconnection that are both internal and external to an entity's reliability footprint. Survey respondents were asked to identify the "major" modeling activities that they were planning in the upcoming year that were "above and beyond of what is considered routine maintenance." Approximately 88 percent (15 of 17) of the RCs and 75 percent (18 out of 24) of other respondents plan make major changes to their network models within the coming year. Table 4.1-7 summarizes these responses.

Major Model Changes in Coming Year	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Adding breaker/switch detail to external model	X	X	X	X			X	X	X							NR	NR	7	**14**
Adding breaker/switch detail to internal model	X	X	X	X	X											NR	NR	7	**12**
Adding extensive telemetry to external model	X	X	X			X	X	X	X							NR	NR	6	**13**
Adding extensive telemetry to internal model	X	X		X	X	X							X			NR	NR	3	**9**
Adding lower-voltage detail to external model	X									X						NR	NR	3	**5**
Adding lower-voltage level detail to internal model	X	X	X	X												NR	NR	4	**8**
Adding one or more control areas to external model	X					X										NR	NR	3	**5**
Creating a new external model	X									X	X	X			X	NR	NR	10	**15**
Others			X		X						X			X		NR	NR	5	**9**

Table 4.1-7 — Major Model Changes Planned in the Upcoming Year

The most common changes planned by the 15 RC respondents are "adding breaker/switch detail to the external model" (47 percent, 7 out of 15), and "adding extensive telemetry to the external model" (47 percent, 7 out of 15). These are closely followed by "adding extensive telemetry to the internal model" (40 percent, 6 out of 15), "adding breaker/switch detail to the internal model" (33 percent, 5 out of 15), and "creating a new external model" (33 percent, 5 out of 15). Therefore, from the table we can see that 75 percent (12 out of 15) of RC respondents are making one or more major changes to their external models in the coming year.

The most common model changes planned by the other non-reliability coordinator respondents are "creating a new external model" (56 percent, 10 out of 18), "adding breaker/switch detail to the external model" (39 percent, 7 out of 18), "adding extensive telemetry to the external model" (33 percent, 6 out of 18), and "adding breaker/switch detail to the internal model" (39 percent, 7 out of 18).

The observations above suggest that most major network model changes that the survey respondents will be implementing in the near term are related to external network model improvements. These types of changes enhance the wide-area analysis capabilities provided by the various EMS network analysis applications that were recommended by Macedo (2004).[8]

[8] Macedo, Frank. Consultant to FERC. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14. http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

Applications that use the Network Model

A total of 41 entities, including 100 percent (17 out of 17) of the RCs, responded to the survey question that identified the applications that use their network models. Table 4.1-8 lists the on-line and off-line applications that use the survey respondents' network models.

Applications that Use the Network Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
State estimator	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	19	**36**
Real-time contingency analysis	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	19	**36**
Study contingency analysis	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	19	**36**
On-line power flow	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		19	**35**
Operator optimal power flow (OPF)		X	X	X		X	X						X	X				6	**13**
Other(s)	X	X	X		X							X						6	**11**
Equipment outage scheduler	X	X	X	X	X				X	X								3	**10**
Volt/Var dispatch (OPF)	X			X			X											5	**8**
Available Transfer Capability and Total Transfer Capability (ATC/TTC) applications	X	X				X		X			X							2	**7**
Market systems	X	X			X	X		X	X	X									**7**
Fault locator			X															2	**3**

Table 4.1-8 — Applications that Use the Network Model

From Table 4.1-8 we see that 100 percent (17 out of 17) of the RCs and 79 percent (19 out of 24) of the other respondents reported that their network models are used by their state estimator, real-time contingency analysis, and study contingency analysis applications. Ninety-four percent (16 of 17) of RCs and 79 percent (19 out of 24) of the other respondents report that their network models are used by their on-line power flow application. One can conclude that these four applications are clearly the ones that all of the survey respondents, regardless of their role, perceive as most important to their operations.

The respondents use their network models in other applications to a lesser extent. From Table 4.1-8 we see that 41 percent (7 out of 17) of the RCs and 25 percent (6 of 24) of the other respondents use their network models in an OPF application. Forty-one percent (7 out of 17) of RCs and 13 percent (3 out of 24) of other respondents use their network models in equipment-outage scheduling applications. Eighteen percent (3 out of 17) of RCs and 21 percent (5 out of 24) of other respondents use their models in Volt/Var dispatch applications (which are generally OPF applications). Twenty-nine percent (5 out of 17) of RCs and 8 percent of the other respondents use their network models in available transfer capability (ATC)/total transfer capability (TTC) applications. Forty-one percent (7 out of 17) of RC respondents and none of the other respondents use their network models in market-related applications. The network models are used by other applications to a lesser extent because:

- Some of the applications listed are only needed by entities that have markets or other special needs.

- Applications such as OPF are much more difficult to implement and maintain than the state estimator, contingency analysis, and on-line power flow. Consequently, they are generally not implemented unless there is a pressing need for them that justifies the cost.

Breaker/Switch Modeling

The survey reveals that, in their internal models, respondents represent a higher percentage of their existing circuit breakers at high-voltage levels than at lower-voltage levels. This is what one would intuitively expect. Table 4.1-9 and Table 4.1-10 summarize the actual survey responses for all RC respondents and non-RC respondents, respectively, regarding this issue.[9]

Voltage Range	N/A	<5 percent	5-25 percent	26-50 percent	51-75 percent	76-95 percent	>95 percent	**Total**
Voltage: 345 - 765 kV	1		1			1	12	**15**
Voltage: 100 - 230 kV	1				2	4	8	**15**
Voltage: < 100 kV	3		3	1		4	4	**15**

Table 4.1-9 — Percentage of Internal System Breakers Modeled for RCs

Voltage Range	N/A	<5 percent	5-25 percent	26-50 percent	51-75 percent	76-95 percent	>95 percent	**Total**
Voltage: 345 - 765 kV	6	2	2				14	**24**
Voltage: 100 - 230 kV	4		1	1	2	4	14	**26**
Voltage: < 100 kV	5		2	3	4	2	9	**25**

Table 4.1-10 — Percentage of Internal System Breakers Modeled for Other (non-RC) Respondents

The survey results also indicate that the higher-voltage portions of the internal system models contain more detail regarding circuit breakers than do the lower-voltage portions. For example, more than 85 percent (12 out of 14, excluding "N/A" responses) of survey respondents state that more than 95 percent of their circuit breakers were modeled for the portions of their internal system models for 345 kV and higher; less than 40 percent (4 out of 14, excluding "N/A" responses) state that 95 percent of their breakers were modeled below the 100-kV level.

Table 4.1-11 and Table 4.1-12 summarize the survey results for modeling internal system switches (i.e., disconnects, gangs, etc.) for RC and other respondents respectively.

[9] The number of respondents varied depending on voltage range. This is probably because some respondents did not select "N/A" for voltage ranges they do not have in their systems.

Voltage Range	N/A	<5 percent	5-25 percent	26-50 percent	51-75 percent	76-95 percent	>95 percent	Total
Voltage: 345 - 765 kV	1		1	2	1	2	8	**15**
Voltage: 100 - 230 kV	1		1	3	2	2	6	**15**
Voltage: < 100 kV	3	1	2	2	1	4	2	**15**

Table 4.1-11 — Percentage of Internal System Switches Modeled for RC Respondents

Voltage Range	N/A	<5 percent	5-25 percent	26-50 percent	51-75 percent	76-95 percent	>95 percent	Total
Voltage: 345 - 765 kV	6	2	-	1	1	1	11	**22**
Voltage: 100 - 230 kV	4		2	3	1	3	11	**24**
Voltage: < 100 kV	5	1	3	1	6	1	7	**24**

Table 4.1-12 — Percentage of Internal System Switches Modeled for Other (non-RC) Respondents

The responses regarding the modeling of switches in the internal system are similar to those regarding the modeling of circuit breakers, as indicated in Table 4.1-11 and Table 4.1-12. The majority of respondents model higher-voltage switches for greater than 95 percent of their systems; lower-voltage switches are generally modeled for less of their systems. By comparing the response summaries in Table 4.1-9 and Table 4.1-10 to those in Table 4.1-11 and Table 4.1-12, we can see that breakers are modeled more often than switches for each voltage range for both RC and other respondents. This is most likely because some entities that include breakers in their models choose not to include disconnect detail in their power system models as a matter of practice.

From these observations, we may conclude that:

1) Survey respondents model breakers and switches in more detail at higher voltages than at lower voltages.
2) Survey respondents model a smaller percentage of their switches than their breakers.

Generator Step-Up Transformer Modeling

Eighty-eight percent (38 out of 43) of survey respondents include at least some of their internal system generator step-up (GSU) transformers in their internal network models. This includes 100 percent (17 out of 17) of RC respondents and 81 percent (21 out of 26) of the other respondents. Table 4.1-13 summarizes the criteria used by the RC and other respondents to determine whether or not a GSU is modeled in their internal network model.

GSU Modeling Criteria for Internal Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Other	**Total**
Based on available telemetry data (SCADA, ISN, etc.)	X	X	X	X	X	X	X	X		X	X	X	X					10	**22**
Based on unit size (MVA)	X	X	X	X	X	X	X	X	X									11	**20**
Other(s)	X	X	X	X					X					X	X	X	X	3	**12**
Based on unit type (coal, nuke, hydro, etc.)	X																	3	**4**
Based on the size of the auxiliary load																		1	**1**

Table 4.1-13 — Modeling Criteria for Internal System Generator Step-Up Transformers

From Table 4.1-13 we see that the most common criterion used to determine whether or not to model a GSU for an internal system generator is the "availability of telemetry data," which was selected by 58 percent (22 out of 38) of the respondents that model internal GSUs. This includes 71 percent (12 out of 17) of the RC respondents and 47 percent (10 out of 21) of the other respondents. This was closely followed by "based on the unit size (MVA)" which was selected by 52 percent (20 out of 38) of the respondents that model internal GSUs. This includes 53 percent (9 out of 17) of the RC respondents and 52 percent (11 out of 21) of the other respondents.

Forty-four percent (19 out of 43) of the survey respondents model GSUs for at least some external generating units in their external system models. This includes 59 percent (10 out of 17) of the RC respondents and 38 percent (10 out of 26) of the other respondents. Table 4.1-14 summarizes the criteria that RC and other respondents use to determine whether or not a GSU for an external generating unit will be included in their external network model.

External GSU Modeling Criteria	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Other	**Total**
Based on available telemetry data	X	X	X	X	X	X					NR	NR	NR	NR	NR	NR	NR	6	**12**
Based on unit size (MVA)	X	X	X	X			X				NR	NR	NR	NR	NR	NR	NR	3	**8**
Other(s)	X							X	X	X	NR	NR	NR	NR	NR	NR	NR	2	**6**

Table 4.1-14 — Criteria Used for Modeling External Network GSUs

From Table 4.1-14 we see that the most common criterion used to determine whether or not to model a GSU for an external system generator is the "availability of telemetry data," which was selected by 63 percent (12 out of 19) of the respondents that model external GSUs. This includes 60 percent (6 out of 10) of the RC respondents and 67 percent (6 out of 9) of the other respondents. This was followed by "based on the unit size (MVA)," which was selected by 42 percent (8 out of 19) of the respondents that model internal GSUs. This includes

50 percent (5 out of 10) of the RC respondents and 33 percent (3 out of 9) of the other respondents that model external GSUs.

It is worth noting that survey respondents favor the same criteria for determining whether or not to model GSUs for both internal and external units. However, both RC respondents and the other respondents model external GSUs to a lesser extent. This is probably because 1) the required modeling information for the external units and their GSUs is more difficult to acquire, and 2) the level of detail required in external models is generally less than that required in internal models.

Generator Auxiliary Load Modeling

Seventy-one percent (29 out of 41) of the respondents model at least some of their internal generating unit auxiliary loads in their internal network models. This includes 71 percent (12 out of 17) of the RC respondents and 71 percent (17 out of 24) of the other respondents. Table 4.1-15 summarizes the criteria used by the RC and other respondents to determine which internal generating unit auxiliary loads to model.

Criteria Used to Determine Which Generating Unit Auxiliary Loads to Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Based on available telemetry data	X	X	X	X		X							NR	NR	NR	NR	NR	10	**15**
Based on unit size (MVA)	X	X	X	X	X				X	X			NR	NR	NR	NR	NR	3	**10**
Based on available MW/Mvar measurements	X	X	X	X	X	X	X						NR	NR	NR	NR	NR	3	**10**
Based on the size of the auxiliary load	X	X				X	X	X					NR	NR	NR	NR	NR	3	**8**
Other(s)	X		X		X						X	X	NR	NR	NR	NR	NR	3	**8**
Based on unit type (coal, nuke, etc.)		X		X				X					NR	NR	NR	NR	NR	1	**4**

Table 4.1-15 — Criteria for Internal Generator Auxiliary Load Modeling

From Table 4.1-15 we see that the most common criterion used to determine whether or not to model generator auxiliary loads for internal system generators is “available telemetry data.” This criterion was selected by 52 percent (15 out of 29) of the respondents that model internal generator auxiliary loads. This includes 42 percent (5 out of 12) of the RC respondents and 59 percent (10 out of 17) of the other respondents. The second and third most common criteria used by the respondents were “unit size” and “available MW/Mvar” measurements. Both of these criteria were selected by 34 percent (10 out of 29) of the respondents which included 58 percent (7 out of 12) of the RC respondents and 18 percent (3 out of 17) of the other respondents.

Only 15 percent (6 out of 41) of the respondents model external generator auxiliary loads in their external network models. This includes 24 percent (4 out of 17) RC respondents and 8 percent (2 out of 24) of the other respondents.

Unit Mvar Capability Curves

Sixty-eight percent (30 out of 44) of the survey respondents reported that they model internal generating unit Mvar capability curves in their internal models. This includes 82 percent (14 out of 17) of the RC respondents and 59 percent (16 out of 27) of the other respondents. It is surprising that 3 of the 17 RCs do not include generating unit capability curves in view of the importance of these curves in determining Mvar reserves and improving voltage calculations by applications such as contingency analysis.[10]

Table 4.1-16 summarizes the methodologies used by respondents that model internal network model generator Mvar capability curves.

[10] RTBPTF did not contact the RCs who were not modeling generating unit Mvar capability curves to determine why they do not model them.

Internal Generating Unit Mvar Capability Curve Development	**RC01**	**RC02**	**RC03**	**RC04**	**RC05**	**RC06**	**RC07**	**RC08**	**RC09**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**RC17**	**Other**	**Total**
Based on original design curves	X	X		X	X									X	NR	NR	NR	13	**18**
Provided by the unit owners	X	X		X	X	X		X	X	X	X	X			NR	NR	NR	3	**13**
Other(s)	X	X	X				X								NR	NR	NR	1	**5**
Approximated based on unit type, size, etc.	X		X										X		NR	NR	NR	2	**5**

Table 4.1-16 — Methodologies Used to Develop Internal Unit Mvar Capability Curve Models

From Table 4.1-16 we see that the most common criterion used to develop internal generator Mvar capability curves was “based on original design curves.” Sixty percent (18 out of 30) of the survey respondents selected this response. This includes 36 percent (5 out of 14) of the RC respondents and 81 percent (13 out of 16) of the other respondents that model internal generator Mvar capability curves. It is not surprising that most of the respondents that chose this answer are the “other” (non-RC) respondents because they would be more likely to be unit owners.

Forty-three percent (13 out of 30) of the respondents base their internal generator Mvar capability models on data provided by the generating unit owners. This includes 71 percent (10 out of 14) of the RC respondents and 19 percent (3 out of 16) of the other respondents that model internal capability curves. It is not surprising that most of the respondents that chose this response were RCs because in many cases they do not own generation and would need to rely on information provided by the asset owners.

Table 4.1-18 summarizes the responses to the question “how do you verify the accuracy of the Mvar capability curves?” There were 30 respondents to this question, which included 14 RC respondents and 16 other respondents.

Verifying the Accuracy of Unit Mvar Capability Curves	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
We do not verify their accuracy									X	X	X	X	X	X	NR	NR	NR	9	**15**
Periodic generator tests at plants	X	X	X	X	X		X	X							NR	NR	NR	6	**13**
Actual response monitoring	X	X	X												NR	NR	NR	2	**5**
Other(s)				X	X	X									NR	NR	NR	2	**5**

Table 4.1-17 — Methodologies Used to Verify Internal Model Mvar Capability Curves

Table 4.1-17 summarizes the survey responses regarding how the respondents that model their internal generator Mvar capability curves verify the accuracy of these curves. Fifty percent (15 out of 30) of the respondents that model them do not verify their accuracy at all. This includes 43 percent (6 out of 14) of the RC respondents and 56 percent (9 out of 16) of other respondents. Of those 15 respondents that do verify their Mvar capability curve accuracy, 87 percent (13 out of 15) of the respondents perform periodic tests at generating plants. The remainder of those who test use “other” means.

Table 4.1-18 summarizes the methodologies used by respondents that model external network model generator Mvar capability curves.

Fifty-one 50 percent (22 out of 43) of the survey respondents report that they model generator Mvar capability curves in their external models. This includes 71 percent (12 out of 17) of the RC respondents and 38 percent (10 out of 26) of the other respondents. Table 4.1-18 summarizes how the respondents develop their external model generating unit Mvar capability curves.

External Generating Unit Mvar Capability Curve Development	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Other	**Total**
Approximated based on units of similar type, size, etc.	X	X	X	X	X	X	X	X					NR	NR	NR	NR	NR	8	**16**
Provided by the unit owners	X								X	X	X		NR	NR	NR	NR	NR	2	**6**
Other(s)									X			X	NR	NR	NR	NR	NR	1	**3**

Table 4.1-18 — Methodologies Used to Develop External Model Mvar Capability Curves

Seventy percent (16 out of 22) of the respondents that model external unit capability curves report that they model external generating unit Mvar capability curves using “approximations based on the generator unit characteristics such as MVA size, type, etc.” This includes 67 percent (8 out of 12) of the RC respondents and 80 percent (8 out of 10) of the other respondents. This is likely because the curve data are more difficult to obtain from the external entities that own the units. In addition, modeling accuracy is not considered a significant issue in most cases because generating units in the external model are usually electrically distant from the internal system. Consequently, inaccuracies in the Mvar capability curves will not usually have a significant impact on the voltages computed by the network applications in the internal portion of the model.

Verifying Transmission Line Characteristics

There were 43 respondents to the survey questions related to the verification of transmission-line characteristics. The respondents included 16 RCs and 27 other respondents.

Table 4.1-19 summarizes the responses and the breakdown of the respondents. Only 46 percent (20 out of 43) of the respondents verify the electrical characteristics of their transmission lines. This includes 50 percent (8 out of 16) of the RC respondents and 44 percent (12 out of 27) of other respondents.

Do you Verify T-Line Characteristics?	RC	Other	**Total**
No	8	15	**23**
Yes	8	12	**20**
Totals	16	27	**43**

Table 4.1-19 — Verification of Transmission-Line Limits

Table 4.1-20 shows the methodology used by each of the 20 respondents that verify transmission line characteristics. The most common method that is used by 65 percent (13 out of 20) of the respondents that verify transmission line characteristics was “based on voltage and flow readings at each end of the line.” This includes 38 percent (3 out of 8) of the RC respondents and 83 percent (10 out of 12) of the other respondents that verify transmission-line characteristics. The second most common method used by 30 percent (6 out of 20) of the respondents was “based on field data and planning models.” These respondents included 3 RCs and 3 other respondents. Surprisingly, only one respondent uses state estimator results. However, respondents may have interpreted “based on voltage and flow readings at each end of the line” as using state estimator readings. Note that only two respondents use actual field tests with special field equipment.

Methods used to Verify T-Line Characteristics	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Based on voltage and flow readings on each end of the line	X	X					X		NR	NR	NR	NR	NR	NR	NR	NR	NR	10	**13**
Based on field data and planning models				X	X			X	NR	NR	NR	NR	NR	NR	NR	NR	NR	3	**6**
Based on data from transmission owner	X		X			X			NR	NR	NR	NR	NR	NR	NR	NR	NR		**3**
Based on field tests with special testing equipment		X							NR	NR	NR	NR	NR	NR	NR	NR	NR	1	**2**
Based on reliable state estimator results									NR	NR	NR	NR	NR	NR	NR	NR	NR	1	**1**

Table 4.1-20 — Methods used to Verify Transmission-Line Characteristics

Transmission Line Real-Time Limits

Nearly 80 percent (33 out of 42) of the respondents reported that their EMS network models support use of “real-time” limits and/or multiple limit sets based on temperatures or seasons for transmission lines. These 33 respondents included 16 RCs and 17 other respondents. Of the 33 respondents that have this capability, 88 percent (29 out of 33) of all respondents make use of these features. This includes 88 percent (14 out of 16) of the RC respondents and 88 percent (15 out of 17) of the other respondents that have this capability. Table 4.1-21 shows how each of the respondents implements real-time limits and/or multiple limit sets for transmission lines.

Methods Used to Implement Real Time Limits	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Discrete limit sets manually selected by operators	X	X	X	X								X	X	X	NR	NR	NR	10	**17**
Dynamically computed from weather variables	X	X	X			X	X			X					NR	NR	NR	3	**9**
Discrete limit sets automatically selected	X	X			X	X	X								NR	NR	NR	1	**6**
Telemetered limits from real-time line rating devices	X		X	X					X						NR	NR	NR		**4**
Others		X			X			X			X				NR	NR	NR	1	**5**

Table 4.1-21 — Methods used to Implement Real-Time Limits

Fifty-eight percent (17 out of 29) of all the respondents that have implemented real-time limits and/or multiple limit sets say that they use “discrete limit sets that are manually selected by the operators” for at least some of their transmission lines. This includes 50 percent (7 out of 14) of the RC respondents and 67 percent (10 out of 15) of the other respondents. Thirty-one percent (9 out of 29) of the respondents use limits that are “dynamically computed from weather variables.” This includes 42 percent (6 out of 14) of the RC respondents and 20 percent (5 of 15) of the other respondents. The acquisition of telemetered limits from real-time rating devices was only used by 14 percent (4 out of 29) of the respondents, which included 29 percent (4 of 14) of the RC respondents and none of the other respondents.

Table 4.1-22 shows the number of limit sets used by the 26 respondents that report that they use of multiple limit sets.

No. Of Limit Sets Used for Lines	RCs	Others	All
2	5	5	10
3	3	3	6
4	2	2	4
7		1	1
8		1	1
16	2		2
20	1		1
24		1	1
Total	**13**	**13**	**26**[11]

Table 4.1-22 — Number of Limit Sets Used for Transmission Lines

[11] These figures do not add up to 29. Apparently some of the respondents (1 RC and 3 other respondents) that said they use multiple limit sets but failed to answer the follow-up questions related to the number of sets used.

The number of limit sets used by the survey respondents varies widely from 2 to 24. It is interesting to note that 38 percent (10 out of 26) of the respondents use only 2 limits sets. This includes 35 percent (5 out of 13) of the RC respondents and 38 percent (5 out of 13) of the other respondents. Seventy-seven percent (20 out of 26) of all respondents and 77 percent (10 out of 13) of the RC respondents use 4 or fewer limit sets.

Transformer Real-Time Limits

Seventy-six percent (32 out of 42) of survey respondents have network models that support the use of real-time limits and/or multiple limit sets based on temperatures or seasons for transformers. This includes 94 percent (16 out of 17) of the RC respondents and 65 percent (17 out of 26) of the other respondents. Of the 33 respondents that have this capability, 76 percent (25 of out 33) are making use of these features. This includes 75 percent (12 out of 16) of the RC respondents and 82 percent (14 out of 17) of the other respondents.

Table 4.1-23 shows the number of limit sets used for transformers by each of the 25 respondents that employ them. As with transmission lines, the number of limit sets used by the respondents for transformers varies widely from 2 to 24 limit sets.

Number of Limit Sets Used for Transformers	RC	Other	All
2	4	6	10
3	5	2	7
4	1	1	2
7	1	1	2
8		1	1
16	2		2
24		1	1
Total	**13**	**12**[12]	**25**

Table 4.1-23 — Number of Transformer Model Limit Sets

Forty percent (10 out of 25) of the respondents, which include 31 percent (4 out of 13) of the RC respondents, use only 2 limit sets. Seventy-six percent (19 out of 25) of the respondents, including 77 percent (10 out of 13) of the RC respondents and 75 percent (9 out of 12) of the other respondents that use multiple limit sets use 4 or fewer sets.

[12] One of the "Other" respondents that uses multiple limit sets did not provide information on how many they use.

Bus Load Modeling

Forty respondents, which include 17 RC respondents and 23 other respondents, answered questions related to the busload modeling capabilities of their EMS network models. Table 4.1-24 summarizes their responses.

EMS Network Model Bus Load Modeling Features and Usage	RCs		Others	
	Supported	Used	Supported	Used
Mapping of real-time load measurements to load models	15	15	17	14
Non-conforming Loads	12	11	14	10
Hourly Loads by day of week and hour	12	9	14	12
Models adapt based on state estimator solution	13	10	9	6
Holiday/Abnormal Day load modeling	11	2	10	2
Hourly Mvar or power factor by day of week and hour	7	5	12	7
Input from the System Load Forecast application	9	6	6	3
MW/Mvar Bus loads vary as function of bus voltage	8	2	6	1
Individual load profile from an external application for an area, bus, feeder, etc.	5	3	4	3

Table 4.1-24 — Load Model Features Supported/Used

Eighty percent (32 out of 40) of the respondents, including 88 percent (15 out of 17) of the RC respondents and 74 percent (17 out of 23) of the other respondents, have the capability to map real-time measurements to the load modeled in their network models. Of those that have this capability, 91 percent (29 out of 32) of the respondents, including 100 percent (15 out of 15) of the RC respondents and 74 percent (14 out of 23) of other respondents, utilize this feature.

Fifty-five percent (22 out of 40) of the respondents, which includes 76 percent (13 out of 17) of the RC respondents and 39 percent (9 out of 23) of the other respondents, have EMS load models that adapt over time based on the state estimator solution. Of the respondents that have this feature, 72 percent (16 out of 22) of the respondents, which include 77 percent (10 out of 13) of the RC respondents and 67 percent (6 out of 9) of the other respondents, make use of it.

Only 35 percent (14 out of 40) of respondents' network models, including 47 percent (8 out of 17) of the RC respondents and 26 percent (6 out of 23) of the other respondents, support voltage-sensitive loads. Of the 14 respondents whose models support this feature, only 21 percent (3 out of 14) actually make use of it.

Table 4.1-25 and Table 4.1-26 below show the frequency of internal and external bus load model updates. Sixty-eight percent (28 out of 41) of the respondents, which includes 65 percent (11 out of 17) of the RC respondents and 71 percent (17 out of 24) of the other respondents, report that the frequency of updates for their internal bus load models is "other." Seventy percent (29 out of 41) of the respondents, which includes 65 percent (11 out of 17) of the RC respondents and 75 percent (18 out of 24) of the other respondents, report that the frequency for updating their external load models is “other.” It was determined from the survey comments that most of the survey respondents interpreted the “other” category to mean “as needed.” A few respondents answered “infrequently” and “never.”

Respondent	Annually	Monthly	Weekly	Other	**Total**
RCs	4	1	1	11	**17**
Others	5		2	17	**24**
All	9	1	3	28	**41**

Table 4.1-25 — Internal Bus Load Model Update Frequency

Respondent	Annually	Monthly	Weekly	Other	**Total**
RCs	6			11	**17**
Others	5		1	18	**24**
All	11		1	29	**41**

Table 4.1-26 — External Bus Load Model Update Frequency

External Network Models

Table 4.1-27 summarizes the methods used by the survey respondents to determine which power system elements (e.g., buses, lines, transformers, generators, etc.) to include in their external network models. There were 43 respondents to this section of the survey, which includes 17 RC respondents and 26 other respondents.

Methods Used to Determine Power System Elements in the External Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Engineering judgment	X	X	X	X	X	X		X	X	X		X	X	X	X	X	X	9	**24**
System planning studies	X	X	X	X			X		X	X								9	**16**
Off-line modeling tools	X	X	X				X	X			X							10	**16**
Other	X	X			X	X												2	**6**
External modeled explicitly				X														2	**3**

Table 4.1-27 — Methods used to Determine External Model Elements

From Table 4.1-27 we see that 59 percent (10 out of 17) of the RCs use multiple methods to determine the elements to include in their external models, and 41 percent (seven out of 17) rely on just one method. Thirty-five percent (6 out of 17) of the RC respondents state that they rely solely on “engineering judgment” to determine the elements to be included in their external models. Thirty-five percent (9 out of 26) of other respondents report that they use “engineering judgment” and/or system planning studies, and 38 percent (10 out of 26) use other off-line modeling tools.

It was very surprising that 35 percent (6 out of 17) of RCs use “engineering judgment” as the sole means of determining what to include in their external models. Seventeen percent (4 out of 24) of the other respondents listed “engineering judgment” as their only means for determining what to include in their external models. Relying solely on engineering judgment to build an external network model is not desirable because it is not always intuitively obvious how much of an interconnection needs to be included in an external model to produce accurate contingency analysis results. Relying entirely on engineering judgment introduces the risk that the external model will be either excessively small or excessively large. If the external model is too small, it can cause erroneous results in real-time contingency analysis, on-line power flow studies, and other applications. If the model is too large, the applications may require significantly more computing resources to arrive at a solution, and the model will require more maintenance resources to keep it current (or it will not be maintained at all).

Table 4.1-28 summarizes the survey results regarding the frequency with which respondents make major changes in their external network models.

Frequency of Major External Model Updates	**RC**	**Others**	**All**
As needed	11	5	16
Annually	3	8	11
N/A		4	4
Infrequently		2	2
Monthly	1	1	2
Depends		1	1
5 years		1	1
Quarterly	1		1
Not done in years		1	1
6-8 weeks	1		1
All	**17**	**23**	**40**

Table 4.1-28 — Frequency of Major External Model Updates

We see that 40 percent (16 out of 40) of the respondents, which includes 65 percent (11 out of 17) of the RC respondents and 22 percent (5 out of 23) of the other respondents, make major changes to their external models as needed. Unfortunately, the survey did not ask them what the average frequency of the “as needed” updates was. Twenty-seven percent (11 out of 40) of the respondents, which includes 18 percent (3 out of 17) of the RC respondents and 35 percent (8 out of 23) of the other respondents, said they make major changes to their external models on an annual basis.

It is difficult to draw any strong conclusions from the responses summarized in Table 4.1-28 except that the external model update frequencies vary widely.

Table 4.1-29 shows the reported starting point for creating (or making additions to) existing external models. There were 41 respondents to this question, including 17 RC respondents and 24 other respondents.

Starting Point for Creating or Adding to the External Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
System planning bus/branch model	X	X		X				X	X	X	X	X	X	X	X	X	X	18	**31**
Detailed model from a previous EMS	X	X				X	X											3	**7**
Others				X	X													4	**6**
Detailed EMS model in proprietary non-vendor format	X	X																1	**3**
CIM XML models from the surrounding entities	X	X	X																**3**
Detailed EMS models in proprietary vendor formats	X		X																**2**

Table 4.1-29 — Starting Point for Creating or Making Additions to the External Model

Seventy-six percent (31 out of 41) of respondents, including 76 percent (13 out of 17) of the RC respondents state that the starting point for creating or making additions to their external models is a system planning model (i.e., a bus-branch model with no breaker/switch detail). It is interesting to note that only 3 of the 41 respondents, all of which are RCs, report that the starting point for their external model (or external model additions) was CIM XML[13] models provided by neighboring entities.

CIM XML is not widely used for building and/or maintaining models for a number of reasons. First, the CIM XML modeling language is relatively new and still evolving. Consequently, some entities with older EMSs can only provide model "dumps" in system planning formats (e.g., PSS/E, GE, etc.) or other proprietary EMS vendor formats. Moreover, the use of CIM XML files for building an external model is still problematic because there are few tools, if any, available to merge a CIM XML model with an existing model. The topic of CIM XML will be discussed further in Section 4.2, Modeling Practices and Tools, of this report.

Eighty percent (33 out of 41) of survey respondents, including 100 percent (17 out of 17) of the RC respondents and 67 percent (16 out of 24) of the other respondents, have at least some real-time analog telemetry linked to their external network models. Table 4.1-30 summarizes this information.

[13] CIM XML has been adopted by NERC Data Exchange Working Group (DEWG) to be the format for exchanging models among transmission system operators.

Have Real-time Analogs Linked to External Model?	RCs	Others	All
None		8	8
Some	17	16	33
Total	**17**	**24**	**41**

Table 4.1-30 — Entities with Real-Time Analog Points in their External Models

Seventy-one percent (29 out of 41) of survey respondents, including 82 percent (14 out of 17) of the RC respondents and 63 percent (15 out of 24) of the other respondents, report that they have at least some real-time status point telemetry linked to their external network models. Table 4.1-31 summarizes this information.

Have Real-time Status Points linked to External Model	RCs	Others	All
None	3	9	12
Some	14	15	29
Total	**17**	**24**	**41**

Table 4.1-31 — Entities with Real-Time Status Points in their External Models

It is worth noting that three RC respondents report that they have no real-time status points in their external models.[14]

The average density of real-time analog and status points linked to the external model is reflected by the ratios of analog and status points in the external model to the number of external model buses. These ratios were computed for the survey respondents that provided sufficient information and are shown in Table 4.1-32, Table 4.1-33, Table 4.1-34, and Table 4.1-35.[15]

The low analog-to-bus ratios in the tables (i.e., fewer than 2 analogs per bus for most of respondents) show that many of the buses in these respondents' external models are likely to be measurement unobservable, from a state estimator perspective, without the use of pseudo-measurements. The low external-status-point-to-external-bus ratios for many respondents (i.e., fewer than 1 status point per bus) indicate that many external buses do not have telemetered breaker/switch information, which implies a bus-branch type external model (i.e., a planning model) for many buses. These ratios may explain why many of the respondents state that they will be adding analog and status points to their external models in the coming year.

[14] These RCs were not contacted to verify the accuracy of their responses.

[15] These ratios could only be computed for the survey respondents that provided both the number of external model buses and the numbers of telemetered analog and status points in their external models.

The lack of real-time telemetry data in the external model was one of the contributing factors in the August 2003 blackout. MISO was using a static bus-branch network model in parts of its external model. When the Stuart-Atlanta 345-kV line tripped (monitored by the PJM RC), MISO's state estimator did not know that the line had gone out of service. This led to a data mismatch that prevented MISO's state estimator from computing a solution that could be used by its real-time contingency analysis application. Without real-time contingency analysis, MISO's ability to see that its system was in danger was greatly compromised.[16]

Resp	No of External Buses	Tel Analog Meas in External	Ext Analog to External Bus Ratio
RC01	15	70	4.67
RC02	9	40	4.44
RC03	60	253	4.22
RC04	445	1,174	2.64
RC05	5,580	11,044	1.98
RC06	17,873	32,476	1.82
RC07	638	1,039	1.63
RC08	1,577	2,153	1.37
RC09	4,837	5,376	1.11
RC10	300	177	0.59
RC11	463	242	0.52
RC12	3,420	936	0.27
RC13	1,575	220	0.14
Count	13	13	13
Average	2,830	4,246	1.95
Median	638	936	1.63
Std Dev	4,894	9,034	1.59
Max	17,873	32,476	4.67
Min	9	40	0.14

Table 4.1-32 — External-Telemetered-Analog-to-External-Bus Ratios for RCs

[16] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 18.

Resp	No. of External Buses	Tel Status Meas in External	Ext Status Pt to External Bus Ratio
RC01	638	2,814	4.41
RC02	9	37	4.11
RC03	15	60	4.00
RC04	5,580	16,496	2.96
RC05	17,873	33,207	1.86
RC06	60	102	1.70
RC07	463	623	1.35
RC08	1,577	1,994	1.26
RC09	4,837	2,382	0.49
RC10	300	129	0.43
RC11	3,420	924	0.27
RC12	445	72	0.16
Count	12	12	12
Average	2,935	4,903	1.92
Median	551	774	1.52
Std Dev	5,097	10,023	1.58
Max	17,873	33,207	4.41
Min	9	37	0.16

Table 4.1-33 — External-Telemetered-Status-Point-to-External-Bus Ratios for RCs

Resp	No of External Buses	Tel Analog Meas in External	Ext Analog to External Bus Ratio
R01	10	334	33.40[17]
R02	630	3,000	4.76
R03	1	4	4.00
R04	1,073	2,545	2.37
R05	2,190	2,751	1.26
R06	40	50	1.25
R07	167	163	0.98
R08	2,505	2,340	0.93
R09	16,138	11,385	0.71
R10	7,100	3,493	0.49
R11	3,090	1,500	0.49
R12	1,722	424	0.25
R13	1,906	423	0.22
R14	504	79	0.16
R15	420	60	0.14
R16	1,952	206	0.11
R17	2	0	0.00
Count	17	17	17
Average	2,321	1,692	3.03
Median	1,073	423	0.71
Std Dev	3,971	2,789	7.94
Max	16,138	11,385	33.40
Min	1	0	0.00

Table 4.1-34 — External-Telemetered-Analog-to-External-Bus Ratios for Non-RCs

[17] This value looks extremely high and may be a data submission error. RTBFTF did not contact the respondent for verification.

Resp	No. Of External Buses	Tel Status Meas in External	Ext Status Pt to External Bus Ratio
R01	10	378	37.80
R02	630	6,000	9.52
R03	1,073	3,173	2.96
R04	167	146	0.87
R05	2,505	1,640	0.65
R06	16,138	9,535	0.59
R07	3,090	1,000	0.32
R08	1,722	517	0.30
R09	7,100	1,832	0.26
R10	40	10	0.25
R11	2,190	535	0.24
R12	420	50	0.12
R13	1,952	157	0.08
R14	504	6	0.01
R15	1,906	0	0.00
R16	1	0	0.00
Count	16	16	16
Average	2,466	1,561	3.37
Median	1,398	448	0.28
Std Dev	4,055	2,656	9.48
Max	16,138	9,535	37.80
Min	1	0	0.00

Table 4.1-35 — External-Telemetered-Status-Point-to-External-Bus Ratios for Non-RCs

Table 4.1-36 summarizes the types of analog points used in the external models of the 33 respondents that have analogs in their external models. The respondents include 17 RCs and 16 other respondents.

Analog Types Linked to External Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
MW	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	16	**32**
Mvar	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X	16	**32**
KV	X	X	X	X	X	X	X		X	X	X	X	X	X	X	X	X	15	**31**
LTC tap positions	X	X	X	X	X			X										4	**10**
Phase-angle regulating transformer taps				X	X			X										2	**5**
Amps	X						X											2	**4**
Line/TX ratings		X				X													**2**
Others	X		X																**2**

Table 4.1-36 — Analog Types Linked to External Model

From the table we see that the MW, Mvar, and KV analog types were reported used in almost 100 percent of the external models because virtually all state estimators use those measurement types. LTC and phase angle regulating (PAR) transformer tap positions are used to a lesser extent. This is probably because some utilities do not have those types of devices on their transmission grids, which is, in turn, because state estimators provided by most vendors support the use of those types of analogs as inputs. PARs are more commonly seen in the northeastern areas of the Eastern Interconnection to mitigate undesirable flow patterns

Table 4.1-37 summarizes the responses regarding the criteria used to select the analog points that are linked to the external models of respondents that have analog points in their external models. There were 33 total respondents, including 17 RC respondents and 16 other respondents. The respondents overwhelmingly selected “engineering judgment” as the leading analog and status point selection criteria, followed by “all measurements above a certain kV level.” Only 3 respondents, 2 of which were RCs, use analytical tools to determine where measurements are needed.

Analog Selection for External Model	**RC01**	**RC02**	**RC03**	**RC04**	**RC05**	**RC06**	**RC07**	**RC08**	**RC09**	**RC10**	**RC11**	**RC12**	**RC13**	**RC14**	**RC15**	**RC16**	**RC17**	**Others**	**Total**
Engineering judgment	X	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	11	**27**
All meas. above a certain kV level	X		X				X	X	X	X	X	X						7	**15**
Other(s)			X	X	X	X												3	**7**
Off-line observability and/or sensitivity studies	X	X																1	**3**

Table 4.1-37 — Analog Selection Criteria used for External Models

Table 4.1-38 summarizes the responses regarding the criteria used to select the status points that are linked to the external models of respondents that have status points in their external models. There were 29 total respondents, including 14 RC respondents and 15 other respondents. The respondents overwhelmingly selected “engineering judgment” as the leading method for both the analog and status point selection criteria, followed by “all measurements above a certain kV level.” Only 3 respondents, 2 of which were reliability coordinators, use analytical tools to determine where measurements are needed.

Status Point Selection for External Model	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	**Total**
Engineering judgment	X		X	X	X	X	X	X			X	X	X	X	NR	NR	NR	10	**21**
Brought in all measurements above a certain kV level	X	X				X	X	X		X					NR	NR	NR	7	**13**
Other(s)		X	X	X	X										NR	NR	NR	4	**8**
Offline observability and/or sensitivity studies	X								X						NR	NR	NR	1	**3**

Table 4.1-38 — Status Point Selection Criteria used for External Models

Recommendations for New Reliability Standards

The RTBPTF recommends no new reliability standards for model characteristics because the Real-Time Tools Survey reveals that entities have significantly different practices for creating and maintaining models of the bulk electric system.

Recommendations for New Operating Guidelines

RTBPTF does not recommend developing operating guidelines related to model characteristics.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for model characteristics. All recommendations for additional analysis related to modeling issues are presented in Section 4.2, Modeling Practices and Tools.

Examples of Excellence

RTBPTF identified no examples of excellence related to Model Characteristics.

Section 4.2
Modeling Practices and Tools

Definition

The term “modeling practices” as used in the context of this report refers to the processes, procedures, and general methodologies used to build and/or maintain mathematical representations of the power system that are used by real-time applications such as the state estimator, contingency analysis, and on-line power flow. “Modeling tools” are the software applications used to build and/or maintain mathematical representations of the power system. They include any applications supplied by vendors, provided by third parties, or created in house.

Background

The *Outage Task Force Final Blackout Report* [18] identifies a number of modeling deficiencies that contributed to the August, 2003 blackout. For example, because MISO did not link real-time measurements to the external portion of its model, the resulting undetected outage of a key transmission line meant that MISO’s state estimator could not converge. Downstream applications that depend on the state estimator solution could therefore not produce accurate representations of the system condition.

Summary of Findings

RTBPTF considers the implementation of modeling practices and tools to be critical to real-time operations. Therefore, a considerable portion of the Real-Time Tools Survey and subsequent analysis were dedicated to examining the various power system network modeling practices and tools that respondents throughout the industry employ to build and maintain the power system models used by their real-time applications.

This analysis is divided into three subsections: power system model updates, data and information exchange, and modeling tools and utilities. The key findings in these areas are:

- Forty-three percent of all survey respondents, including 53 percent of the RC respondents, model future grid changes by using temporary, fictitious “dummy” switches that allow the new equipment element(s) to be switched into service and/or old equipment elements to be switched out of service when anticipated changes actually take place in the field. The dummy switches are removed on subsequent updates.

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[18] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April. p. 18.

- Respondents report network model update frequencies ranging from 1- to 12-week intervals. Forty percent of all respondents, including 50 percent of the RC respondents, update their models on a weekly basis.

- Seventy-five percent of all respondents, including 82 percent of the RC respondents, formally document changes and updates to their network models.

- Fifty-six percent of all respondents, including 71 percent of the RC respondents, have some form of documented testing and quality assurance (QA) procedures for their network model changes. Surprisingly, some of the respondents, including a few RCs, place model changes on line with no prior testing.

- Sixty-one percent of all respondents, including 88 percent of the RC respondents, have documented procedures to communicate internal system changes to EMS network modeling personnel.

- Only 35 percent of the survey respondents have formal agreements and/or processes to notify and/or be notified by entities external to their reliability areas about transmission grid changes. Fifty-nine percent of the RC respondents have such processes and procedures. This is surprisingly low, especially for the RCs because of their responsibilities.

- Fifty-five percent of respondents have agreements and procedures for exchanging modeling data with external entities. Fifty-three percent of the RC respondents have such procedures.

- Only 29 percent of survey respondents have model merge utilities, and only 41 percent of the RC respondents have such tools. This means that 59 percent of the RCs have no tools and must use only manual means to incorporate new model additions into their existing models. This highlights a significant need for model merge tools to maintain large power system models.

- Forty-one percent of respondents have network reduction/equivalencing tools, and 47 percent of the RC respondents have these tools. These tools are typically used for external model creation.

- Less than 25 percent of respondents say they have used CIM XML files to either import models from other entities or export their model for use by other entities. Information from the model characteristics section of the survey seems to imply that less that 10 percent of the respondents are using CIM XML files for external model updates.

The subsections that follow present a detailed analysis of the survey data on which the above findings are based.

Power System Model Updates

The survey collected information related to several areas of power system model maintenance, including methods of modeling of future grid changes, the frequency with which production network models are updated, documentation of network model changes, automatic logging of network model changes, QA and testing of network model changes, and testing of changes before they are put on line.

Modeling of Future Grid Changes

Table 4.2-1 summarizes respondents' reported methods of integrating future grid changes into network models in a timely manner. There were 40 respondents, including 17 RC respondents and 23 other respondents.[19]

How Do You Model Future Grid Changes?	RCs	Others	**Total**
Add future elements and "dummy" switches to connect/disconnect future/old equipment	9	8	**17**
Perform an immediate database update on-line to reflect the database changes	5	5	**10**
Perform changes on backup and fail over	3	6	**9**
Perform immediate partial model update on line		4	**4**
All	**17**	**23**	**40**

Table 4.2-1 — Modeling Future Network Model Changes

Respondents chose one of four methods for modeling future network changes. Forty-three percent (17 out of 40) of all respondents, including 53 percent (9 out of 17) of the RC respondents and 35 percent (9 out of 23) of the other respondents, model future grid elements by using temporary "dummy" switches that allow new equipment element(s) to be switched into service and/or the old equipment element(s) to be switched out of service when anticipated changes actually take place in the field. These temporary switches and other elements are subsequently removed when a new database is put in service that incorporates all of the grid changes. Twenty-five percent (10 out of 40) of respondents, including 29 percent (5 out of 17) of the RC respondents and 22 percent (5 out of 23) of the other respondents, perform immediate database updates on line to reflect the addition/removal of equipment in the field when the equipment is actually placed into/out of service. Twenty-two percent (11 out of 40) of the respondents, including 18 percent (3 out of 17) of the RC respondents and 26 percent (6 out of 23) of the other respondents, make the changes in their backup system databases and then fail over to the new database when the

[19]Respondents without models were not included in the table.

equipment in the field goes into or out of service. Ten percent (4 out of 40), including 0 percent (0 out of 17) of the RC respondents and 17 percent (4 out of 23) of the other respondents, perform immediate partial model updates on line.

The respondents' choices of methods appear to depend largely on their EMSs' database modeling capabilities (i.e., features provided by the EMS vendor) and the sizes of their databases. Respondents that have on-line database-change capabilities use them (see the "Modeling Tools and Utilities" subsection below). Respondents without on-line database editing capabilities use one of the other two methods identified in Table 4.2-1; the majority of RC respondents without on-line editing capabilities favor the "dummy switch" approach for modeling future system changes.

Frequency of Network Model Updates

Table 4.2-2 summarizes the survey responses regarding frequency of production network model updates. There were a total of 40 respondents to this question, including 16 RC respondents and 24 other respondents.

Network Database Update Frequency	RC	Others	Total
Weekly	8	8	**16**
3 Weeks	2	3	**5**
Monthly	2	4	**6**
6 Weeks	1		**1**
12 Weeks	3	2	**5**
As needed		7	**7**
Total	**16**	**24**	**40**

Table 4.2-2 — Production Network Model Update Frequency

Respondents report network model update frequencies ranging from 1- to 12-week intervals, with unscheduled updates performed "as needed." Forty percent (16 out of 40) of the respondents, including 50 percent (eight out of 16) of the RC respondents and 33 percent (8 out of 24) of the other respondents, update their models weekly. Twenty-eight percent (11 out of 40) of respondents, including 25 percent (4 out of 16) of the RC respondents and 29 percent of the other respondents, update their models every 3 to 4 weeks. Respondents with markets report less frequent updates, most likely because of the complexities of market-related applications, the larger model sizes, and the associated auditing requirements.

Documentation of Network Model Changes

Table 4.2-3 summarizes the survey responses regarding documentation of network model changes. There were 40 respondents to this question, including 17 RC respondents and 23 other respondents.

Are Network Model Changes and Updates Formally Documented?	RC	Other	All
No	3	7	10
Yes	14	16	30
Totals	**17**	**23**	**40**

Table 4.2-3 — Formal Documentation of Network Model Changes

Seventy-five percent (30 out of 40) of the respondents, including 82 percent (14 out of 17) of the RC respondents and 70 percent (16 out of 23) of the other respondents, formally document the changes and updates made to their network models. All RCs that operate in markets formally document their network model changes, as would be expected.

Automatic Logging of Network Model Changes

Table 4.2-4 summarizes the survey responses regarding the automatic logging of network model changes. There were 40 respondents to this question, including 17 RC respondents and 23 other respondents.

Are Network Model Changes Automatically Logged by Modeling Tools?	RC	Other	All
No	11	18	29
Yes	6	5	11
Totals	**17**	**23**	**40**

Table 4.2-4 — Automatic Logging of Network Model Changes

Only 27 percent (11 out of 40) of respondents, including 35 percent (6 out of 17) of the RC respondents and 22 percent (5 out of 23) of the other respondents, have modeling tools that automatically log changes made to their network models. The responses summarized in Table 4.2-3 and Table 4.2-4 seem to imply that those that document network model changes do so largely manually.

Quality Assurance and Test Procedures for Network Model Changes

Table 4.2-5 summarizes survey responses related to documented model testing and quality assurance (QA) procedures. There were 39 respondents for these questions, including 17 RC respondents and 22 other respondents.

Has documented model change testing & QA procedures	RC	Other	All
No	5	12	17
Yes	12	10	22
Totals	**17**	**22**	**39**

Table 4.2-5 — Documented Model Testing and QA Procedures

Fifty-six percent (22 out of 39) of respondents, including 71 percent (12 out of 17) of the RC respondents and 45 percent (10 out of 22) of the other respondents, indicate that they have some form of documented testing and QA procedures for their network model changes. All of the RC respondents that operate in markets have these procedures, as one would expect. It is surprising that 29 percent (5 out of 17) of the RC respondents have no documented network model testing and quality assurance procedures.

Testing Model Changes Prior to Putting Model On-Line

Table 4.2-6 summarizes the survey responses related to testing network models before placing them on line in the production environment. There were a total of 39 respondents to these questions, including 17 RC respondents and 22 other respondents.

Model Change Testing Methodologies	RC01	RC02	RC03	RC04	RC05	RC06	RC07	RC08	RC09	RC10	RC11	RC12	RC13	RC14	RC15	RC16	RC17	Others	Total
Development EMS with live data	X	X	X	X	X	X	X	X	X	X	X	X						10	**22**
Development EMS with no live data	X	X	X										X	X	X			1	**7**
Place on line with no tests, verify on-line																X	X	11	**13**
Test on a DTS						X												4	**5**
Use study power flow and/or study contingency analysis to test changes					X														**1**
Test using off-line model															X				**1**
Test on backup system using real-time telemetry				X															**1**

Table 4.2-6 — Model Change Testing Methodologies

Fifty-six percent (22 out of 39) of respondents, including 71 percent (12 out of 17) of the RC respondents and 45 percent (10 out of 22) of the other respondents, test their network models on a development (i.e., test bed) system that allows testing with live SCADA data. Only 33 percent (13 out of 39) of respondents, including 12 percent (2 out of 17) of the RC respondents and 50 percent (11 out of 22) of the other respondents, place their model changes on the production system with no testing prior to putting the models on line. They test their models on line after they are put into production.

A higher percentage of RCs than other respondents perform testing with live data on a development system prior to putting their models on-line. However, considering the function and responsibilities of RCs, one might expect an even higher percentage. Eighty-eight percent (15 out of 17) of the RC respondents perform some type of model testing prior to putting models on line. However, 3 of these respondents do not use live SCADA data in their testing.

Data and Information Exchange

The subsections below present the survey results for data and information exchange processes and procedures.

Processes and Procedures for Communicating Planned and Actual Internal System Transmission Grid Changes to Modeling Personnel

Table 4.2-7 summarizes the survey responses regarding "processes and procedures for communicating planned and actual internal system changes to EMS modeling personnel." The "internal system" refers to the portion of the grid for which the survey respondent has responsibility (i.e., the respondent's reliability footprint). There were a total of 41 respondents to this question, including 17 RC respondents and 24 other respondents.

Has Formal Notification Process for Internal System Changes	RC	Other	**All**
No	2	14	**16**
Yes	15	10	**25**
Totals	**17**	**24**	**41**

Table 4.2-7 — Has Formal Notification Processes for Internal Grid Changes

Sixty-one percent (25 out of 41) of the respondents, including 88 percent (15 out of 17) of the RC respondents and 42 percent (10 out of 24) of the other respondents, have documented procedures to communicate internal system changes to EMS network modeling personnel. The percentage of RCs with these procedures is significantly higher than the percentage of respondents who are not RCs. This is probably because:

- RCs typically have larger systems and thus larger models to maintain, so they need a more structured approach for learning about changes.
- Many RCs do not own some (or even any) of the transmission assets in their reliability footprint. Consequently, they are very dependent on the asset owners to provide them information on when things are changed in the field.

Table 4.2-8 summarizes the value for situational awareness that the respondents place on these procedures by those that actually have them.

Value of Internal Grid Change Notification Procedures	RC	Other	All
Essential	13	8	**21**
Desirable	1		**1**
Minimal Value	1		**1**
No Value		1	**1**
Totals	**15**	**9**	**24**

Table 4.2-8 — Value of Internal Grid Change Notification Procedures

Eighty-eight percent (21 out of 24) of the respondents that have these procedures, including 87 percent (13 out of 15) of the RC respondents and 89 percent (8 out of 9) of the other respondents, consider them "essential" for situational awareness. Only one RC respondent indicates that its procedures were of "minimal" value. Eight out of 9 of the non-RC respondents that have documented procedures stated that these procedures are "essential."

A high percentage of the RC respondents (88 percent, 15 out of 17) have procedures for communicating to EMS support staff any changes in internal grids. This is not surprising because many RCs own only a fraction of the transmission assets in their reliability footprint and are therefore dependent on the asset owners to report when changes have been made and/or when they are going to occur. All of the RCs that operate in markets have these types of procedures.

Processes and Procedures for Communicating Planned and Actual Transmission Grid Changes with External Entities

Table 4.2-9 summarizes the survey responses regarding documented "processes and procedures for communicating planned and actual system changes with external entities." The "external system" refers to that portion of the grid that is not in the respondent's reliability area of responsibility (e.g., outside the RC or TOP system footprint). There were a total of 40 respondents for this question, which included 17 RC respondents and 23 other respondents.

Formal Notification Processes and Procedures with External Entities on Planned Grid Changes	RC	Other	All
No	7	19	**26**
Yes	10	4	**14**
Totals	**17**	**23**	**40**

Table 4.2-9 — Formal Notification Processes and Procedures with External Entities for Planned Grid Changes

Table 4.2-10 indicates the value for situational awareness placed on these procedures by the respondents that have them.

Value of Formal Notification Processes and Procedures with External Entities on Planned Grid Changes	RC	Other	**All**
Essential	7	1	**8**
Desirable	3	2	**5**
Minimal Value		1	**1**
No Value		1	
Totals	**10**	**4**	**14**

Table 4.2-10 — Value of formal Notification Processes and Procedures with External Entities

From Table 4.2-10 we see that only 35 percent (14 out of 40) of the survey respondents have formal agreements and/or processes to notify and/or be notified by entities external to their reliability area regarding planned and actual changes to the physical transmission grid. This includes 59 percent (10 out of 17) of the RC respondents and 17 percent (4 out of 23) of the other respondents.

Of those that have these procedures, 57 percent (8 out of 14) of the respondents, which includes 70 percent (7 out of 10) of the RC respondents and 25 percent (1 out of 4) of the other respondents, consider them "essential."

Maintaining a current and accurate external network model to support contingency analysis and a wide-area view would, at a minimum, appear to require processes and procedures for knowing about major changes in external transmission systems. But many of the survey respondents, including a significant number of RCs, do not have such procedures. It should be noted that the NERC DEWG has written procedures for notifying other RCs, TOPs, and similar entities about upcoming changes in the power grid. However, these procedures are neither enforced nor strictly followed. The "Planned Power System Model Change Notification Process" document can be downloaded from the DEWG section of the NERC website (http://www.nerc.com/~filez/isn.html).

Processes and Procedures for Communicating EMS-Related Changes to External Entities

Table 4.2-11 summarizes the survey responses regarding "processes and procedures for communicating planned and actual EMS-related changes with external entities." "EMS-related changes" are changes related to EMS databases, networks, and other components that can affect entities that receive/send data from/to them. Examples of such changes are addition and/or deletions of new SCADA points, alterations related to communication links (e.g., IP address changes), changes to ICCP object IDs, etc. There were a total of 40 respondents to this question, which included 16 RC respondents and 24 other respondents.

Have Formal Notification Processes and Procedures with External Entities on Planned and Actual EMS Change Notification	RC	Other	All
No	7	18	**25**
Yes	9	6	**15**
Totals	**16**	**24**	**40**

Table 4.2-11 — Processes and Procedures for Communicating EMS-Related Changes to External Entities

Table 4.2-12 summarizes the value for situational awareness of the processes and procedures for those respondents that have them.

Value of Formal Notification Processes and Procedures with External Entities on Planned and Actual EMS Change Notification	RC	Other	All
Essential	7	2	**9**
Desirable	2	2	**4**
Minimal Value		2	**2**
No Value			
Totals	**9**	**6**	**15**

Table 4.2-12 — Value of Processes and Procedures to Communicate EMS Changes with External Entities

Table 4.2-12 indicates that 40 percent (16 out of 40) of respondents, including 56 percent (9 out of 16) of the RC respondents and 25 percent (6 out of 24) of the other respondents, have processes and procedures for notifying external entities about EMS-related changes. Of the 16 respondents that have these procedures, 87 percent (13 out of 15) consider them either “desirable” or “essential” for situational awareness. All (9 out of 9) of the RC respondents that have EMS change notification procedures state that these procedures are either “essential” or “desirable” for situational awareness. Sixty-seven percent (4 out of 6) of the other respondents that have these procedures stated that they were either “essential” or “desirable.”

It is surprising that only 9 RC respondents have these procedures because they are more likely than the other respondents to acquire real-time SCADA information from external EMS systems to support their wide-area models. However, this finding is consistent with the model information that was discussed in Section 4.1, Model Characteristics, of this report (e.g., the computed external-measurement-to-external bus ratios). However, we see from the survey responses that all 9 of the RCs who have these procedures consider them desirable or essential.

The NERC DEWG has written “*ISN Node Responsibilities and Procedures*,*”* which includes procedures that should be followed by entities that exchange real-time data via the ISN. Procedures include notification of server outages, software upgrades, data changes, and other related items. These procedures are not strictly enforced, however.

Agreements and Procedures for Exchanging Transmission Model Data with External Entities

Table 4.2-13 summarizes the survey responses regarding “agreements and procedures for exchanging transmission modeling data with external entities.” There were 40 respondents to these questions, which included 17 RC respondents and 23 other respondents.

Transmission modeling data include typical network model information (e.g., breaker and switch connectivity data, line and transformer parameters, generating unit parameters, etc.) in addition to supporting information such as station schematics, geographic maps, etc.

Has Formal Agreements and Procedures for Exchanging Modeling Information with External Entities	RC	Other	**All**
No	8	10	**18**
Yes	9	13	**22**
Totals	**17**	**23**	**40**

Table 4.2-13 — Agreements and Procedures for Exchanging Modeling Information with External Entities

The survey responses indicate that 55 percent (22 out of 40) of respondents, including 53 percent (9 out of 17) of the RC respondents and 57 percent (13 out of 23) of the other respondents, have agreements and procedures with external entities for exchanging modeling data.

The number of respondents with agreements and procedures for exchanging modeling information with external entities is surprisingly low, especially for the RCs. It would seem that RCs would need such procedures in place to help maintain the larger models required for their wide-area view.

Table 4.2-14 summarizes the value for situational awareness placed on data-exchange agreements with external entities by the 21 respondents that have such agreements.

Value of Formal Agreements and Procedures for Exchanging Modeling Information with External Entities	RC	Other	All
Essential	5	3	**8**
Desirable	4	4	**8**
Minimal Value		1	**1**
No Value		4	**4**
Totals	**9**	**12**	**21**

Table 4.2-14 — Value of Formal Data Exchange Agreements with External Entities

From the responses we see that 76 percent (16 out of 21) of those that have these procedures, including 100 percent (9 out of 9) of the RC respondents and 58 percent (7 out of 12) of the other respondents, think these procedures are either “essential” or “desirable” for situational awareness.

Modeling Tools and Utilities

“Modeling tools,” as defined in this report, are software applications used to build and/or maintain power system models. They include any applications supplied by vendors, provided by third parties, or created in-house. The subsections below summarize the results for the modeling tools portion of the Real-Time Tools Survey.

On-line Database Editing Capabilities

Table 4.2-15 summarizes the survey respondents’ on-line SCADA data editing capabilities. There were 43 respondents to this question, which included 17 RC respondents and 26 other respondents. Fifty-six percent (24 out of 43) of respondents, which included 65 percent (11 out of 17) of the RC respondents and 50 percent (13 out of 26) of the other respondents, have some form of on-line SCADA data editing capabilities in their EMSs.

Can you Edit existing SCADA Model Information Online?	RC	Other	All
No	6	13	**19**
Yes	11	13	**24**
Total	**17**	**26**	**43**

Table 4.2-15 — On-Line SCADA Database Editing Capability

Table 4.2-16 summarizes the value for situational awareness that respondents with on-line SCADA data editing place on this capability.

How do You Rank the Value of this On-line SCADA Editing Capability as Applied in Your Modeling Activities?	RC	Other	**All**
Essential	6	6	**12**
Desirable	4	5	**9**
Minimal Value	1	2	**3**
No Value			
Total	**11**	**13**	**24**

Table 4.2-16 — Value of On-Line SCADA Model Editing Capability

From Table 4.2-16 we see that 88 percent (21 out of 24) of the respondents that have on-line SCADA model editing capability, including 91 percent (10 out of 11) of the RC respondents and 85 percent (11 out of 13) of the other respondents, that have this capability think that it is either "desirable" or "essential" for situational awareness. Only 12 percent (3 out of 24) of respondents that have this feature, which included 1 RC and 2 other respondents, felt that this feature adds minimal value.

In general, on-line SCADA data editing capability is a feature that would only be provided by an EMS vendor as part of its proprietary database support tools. This is not a feature that one would expect to be implemented in house by EMS support personnel.

Table 4.2-17 summarizes the on-line network model data editing capabilities of the survey respondents. There were 40 respondents to this question including 16 RC respondents and 24 other respondents.

Can You Edit Network Model Database Information Online?	RC	Other	**All**
No	6	14	**20**
Yes	10	10	**20**
Total	**16**	**24**	**40**

Table 4.2-17 — On-Line Network Model Database Editing Capability

Table 4.2-17 indicates that 50 percent (20 out of 40) of the respondents, including 63 percent (10 out of 16) of the RC respondents and 42 percent (10 out of 24) of the other respondents, have on-line network model editing capabilities on their EMS. As with on-line SCADA data editing, on-line network modeling is almost exclusively a feature provided only by EMS vendors. This is not a feature that one would expect to be implemented in house by EMS support personnel.

Unfortunately, the Real-Time Tools Survey was not specific about the meaning of "on-line database editing." For instance, the survey did not differentiate among "add," "modify," and "delete" capabilities. Many EMS tools allow modification of existing data items (e.g., changing SCADA limits, line impedances or limits), but do not allow the addition or deletion of new items. Consequently, 2 survey respondents that both have on-line database editing could have answered this question in opposite ways, depending on what they interpreted it as covering.

Supplemental Model Validation Tools

Table 4.2-18 summarizes survey responses related to supplemental database validation tools. Supplemental database validation tools are applications that provide EMS database error and consistency checking above and beyond what the EMS vendor provides in its standard product. There were a total of 42 respondents to this question that included 17 RC respondents and 25 other respondents.

Supplemental Database Validation Tools	RC	Other	**All**
No	6	20	**26**
Yes	11	5	**16**
Totals	**17**	**25**	**42**

Table 4.2-18 — Supplemental Database Validation Tools

Thirty-eight percent (16 out of 42) of the respondents, including 65 percent (11 out of 17) of the RC respondents and 20 percent (5 out of 25) of the other respondents, have supplemental database validation tools. Significantly more RC respondents have these types of utilities compared to other respondents. This is probably because the RCs are generally larger organizations than other respondents and may have more support staff to develop such tools. Additionally, RCs generally have larger network models and more data to maintain.[20] Consequently, RCs have a greater need for such tools and can justify the resources required.

Network Model Merge Tools

Network model merge utilities allow users to merge a partial or full network model with an existing network model. These types of utilities are needed to facilitate activities such as replacing an existing external network model with a new one. Table 4.2-19 summarizes the survey respondents' model-merge capabilities.

Has Network Model Merge Tools	RC	Other	All
No	10	20	**30**
Yes	7	5	**12**
Totals	**17**	**25**	**42**

Table 4.2-19 — Network Model Merge Tools

There were 42 respondents to this question, including 17 RC respondents and 25 other respondents. Only 28 percent (12 out of 43) of the respondents, which

[20] RC respondents average almost twice as many buses and branches in their network models as do the other survey respondents.

include 41 percent (7 out of 17) of the RC respondents and 20 percent (5 out of 15) of the other respondents, have network model merge utilities.

The fact that 59 percent (10 out of 17) of the RC respondents do not have model merge tools suggests that there is a significant need for tools to maintain large power system models. This implies that many of the RCs are required to maintain their internal and external models more or less manually. For instance, if a new balancing authority is added to an RC's existing footprint and the RC does not have model merge utilities, it has the tedious task of manually adding the detailed model of the new balancing authority to the existing network model. This is a significant issue because many RCs and others are expanding the sizes of their internal and/or external models to enhance their wide-area views.

Network Reduction/Equivalencing Tools

Network reduction and equivalencing utilities are applications that take a given network model as input and generate a smaller reduced and/or equivalent model using network reduction algorithms and the user's specific input instructions on what power system elements to preserve, etc. This type of tool is particularly useful when building the external portion of a network model using network models from other entities (e.g., a model of the interconnection) as a starting point. Table 4.2-20 summarizes the survey responses related to these types of tools. There were a total of 42 respondents to these questions, including 17 RC respondents and 25 other respondents.

Has Network Reduction and Equivalencing Tools?	RC	Other	All
No	9	16	**25**
Yes	8	9	**17**
Totals	**17**	**25**	**42**

Table 4.2-20 — Network Reduction/Equivalencing Tools

Table 4.2-20 indicates that 40 percent (17 out of 42) of respondents, including 47 percent (8 out of 17) of the RC respondents and 36 percent (9 out of 25) of the other respondents, have network reduction/equivalencing tools.

These results suggest that 53 percent of the RC respondents and 64 percent of the other respondents do one of the following:

- use a model of the external world that is not simplified in any way
- use an external model that was generated using “engineering judgment” to determine the buses, lines, and other elements
- have a third party build an external model for them
- have no external model

The responses from the model characteristics section of the survey suggest that many of the respondents that do not have network reduction tools are relying on “engineering judgment” to select the elements to keep in their external models.

Table 4.2-21 summarizes the responses to the question for respondents that have network reduction/equivalencing tools, “Do you use these tools?”

Do You Use Network Reduction and Equivalencing Tools?	RC	Other	All
No	3	2	**5**
Yes	5	7	**12**
Totals	**8**	**9**	**17**

Table 4.2-21 — Use of Network Reduction/Equivalencing Tools by those that Have Them

Seventy-one percent (12 out of 17) of the respondents that have these tools, including 63 percent (5 out of 8) of the RC respondents and 78 percent (7 out of 9) of the other respondents, actually use them. Those that do not use them probably rely on engineering judgment when creating their external models.

CIM XML Export/Import Capabilities and Usage

Tables 4.2-22, 4.2-23, and 4.2-24 summarize the survey responses regarding CIM XML import/export capabilities and usage. There were a total of 41 respondents to this set of questions, which included 17 RC respondents and 24 other respondents (see Table 4.2.22).

Do You Have CIM XML Import/Export Capabilities?	RC	Other	**All**
No	8	16	**24**
Yes	9	8	**17**
Total	**17**	**24**	**41**

Table 4.2-22 — CIM XML Import/Export Capability

The responses show that 41 percent (17 of 41) of the respondents, including 53 percent (9 out of 17) of the RC respondents and 33 percent (8 out of 24) of the other respondents, have CIM import/export capability. The 17 respondents that have this capability were asked if they use it. Their responses are summarized in Table 4.2-23 below.

Do You Use Your CIM XML Import/Export capability?	RC	Other	**All**
No	3	4	**7**
Yes	6	4	**10**
Totals	**9**	**8**	**17**

Table 4.2-23 — Use of CIM XML Import/Export Capability by those that Have It

The response data in Table 4.2-23 shows that 59 percent (10 out of 17) of the respondents that have CIM XML import/export capability, including that 66 percent (6 out of 9) of the RC respondents and 50 percent (4 out of 8) of the other respondents, actually use it for importing and/or exporting models in CIM XML format.

Unfortunately, the survey did not specifically ask the respondents if they were using this capability for importing models, exporting models, or both. However, in Section 4.1, Model Characteristics, only 3 respondents, all of which are RCs, said they use CIM XML models as the starting point for building their external models, which would require importing CIM XML models. Conversely, this seems to imply that 7 of the 10 respondents that use their CIM XML import/export capability are using it to export models (perhaps to send to others to use?) and not to import them.

The 10 survey respondents who said they used CIM import/export capability were asked to rank the value of this capability. Table 4.2-24 summarizes the responses to this question.

How Do You Rank the Value of CIM XML File Import/Export as Applied in Your Modeling Activities?	RC	Other	All
Essential	1	3	**4**
Desirable	3	3	**6**
Minimal			
No Value			
Totals	**4**	**6**	**10**

Table 4.2-24 — Value of CIM XML Import/Export by Those that Actually Use It

From Table 4.2-24 we see that all 10 of the respondents who use CIM XML import/export capability say that it is either an “essential” or “desirable” feature as applied to their modeling activities. Only 1 of the 4 RC respondents said it was “essential,” and 3 of the 6 non-RC respondents said it was “essential.”

These “value” responses seem inconsistent when coupled with the fact that only 3 of the 10 respondents say that they use CIM XML imports as the starting point of their external models. (All 3 were RCs.) It may be that those that use the capability only to export models say it is essential because they are required to provide CIM XML models to others (e.g., their RCs). Or, it could be that the respondents placed a high value on this capability because CIM XML will very likely be the model exchange language of the future and they have plans to use it. Unfortunately, the survey questions related to CIM XML were not as thorough and concise as they could have been.

In an attempt to better understand the apparent inconsistencies in the survey responses, the task force contacted for follow-up questions 3 of the respondents that have used their CIM XML import/export capabilities in their modeling activities. All of those contacted were RCs who have some of the largest network models in the survey. Two of the 3 had used CIM XML models that were provided to them by other entities for major internal and external model additions and replacements, and one has just used a CIM XML model for internal model updates. Some of the interesting pieces of information that came from the follow-up questions are summarized below:

- CIM XML files have been used infrequently and only for major model additions and replacements. None of the 3 had used it for relatively small changes (e.g., incremental updates) that would be considered as “routine” model maintenance.
- It is not a “plug and play” process and generally takes weeks or months to implement changes. For instance, one respondent stated that some CIM XML files require one to two weeks to complete the import, conversion, and some basic model validation. When there is a problem with the source CIM XML file (because of data, syntax, or schema), they must request an updated version of the source model. Every request for an updated source model and the subsequent import/conversion requires two

to three weeks, so multiple requests for an updated source model can easily add three months (or more) to a project before the model reduction and model merge steps can even begin.

- Merging a CIM XML model into an existing network model is an involved process that entails both automated and manual work. The respondents have had to write special software tools to aid in their efforts.
- Some entities cannot dump their models in CIM XML output files to other entities because their EMSs do not have that capability. In that case, the receiving entities must accept files in other formats and use them to update their models.
- None of those contacted has used the CIM XML models for measurement mapping. This has done manually or by supplemental data files and tools that were created for that purpose.
- The import of the CIM XML model does not provide 100 percent of what is needed for a complete model. Custom programming and/or manual data entry is often needed to populate missing or incorrect data in the source model.

Some of the major technical issues that the respondents said they had to overcome were:

- CIM XML files do not always comply with the NERC CPSM.
- There is some room for interpretation of the CIM standard, and, as a result, certain data are not put in the data classes or attributes where another vendor would expect to find them.
- Vendor tools are not always compatible with the exact version of CIM that was used to create the source model.
- Attempts to resolve data issues by browsing XML files are nearly impossible because the files are difficult to read. Better tools are needed to review the CIM XML files for troubleshooting.
- CIM XML files are extremely large. The large file sizes stress (and sometimes break) the tools that are used to import and convert the models.

The CIM definition for power system modeling is still under development and is evolving. Most of the major EMS vendors are participating in interoperability tests to work out the existing bugs and to test new features (e.g., incremental updates). There is also an active users group that has been created to develop the CIM related standards (http://www.cimusers.org). However, despite the push in the industry to adopt and use CIM XML, the survey responses suggest that CIM XML model exchange is not yet common practice. Only 42 percent (17 out of 41) of the respondents can even export their models in CIM XML files. And only 58 percent (10 out of 17) of those that have it, and 24 percent (10 out of 41) of all survey respondents, are using it at all. Despite these challenges, the respondents that were contacted expect to be using CIM XML to a greater extent in the future as technical problems are solved and users and EMS vendors create new tools.

Recommendations for New Reliability Standards

RTBPTF makes no recommendations at this time for reliability standards related to modeling practices. However, RTBPTF recommends that additional analysis be done in several modeling areas from which recommendations for new reliability standards may be forthcoming.

Recommendation – A16

Investigate processes and procedures for internal system update and external data exchange, including CIM XML models.

Areas Requiring More Analysis

RTBPTF has identified the following areas for more analysis:

- Clarity of fundamental definitions of terms used in the existing NERC reliability standards
- Processes and procedures for grid change notification and data exchange
- Development of external system modeling guidelines
- Exchange of CIM XML models

Clarity of Fundamental Definitions

RCs and other entities have been charged with monitoring their "bulk electric systems" and having network models that provide a "wide-area view." However, existing definitions of "bulk electric system," "bulk power system," and "wide-area view" are vague and open to interpretation as evidenced by the significant variation in models reported in the Real-Time Tools Survey. An entity's interpretation of these definitions can significantly impact the size and contents of the network model it uses for its real-time applications, and, consequently, the maintenance efforts needed to keep that model current. The vagueness of these terms may partially explain some of the large differences in model sizes and characteristics that were identified in Section 4.1, Model Characteristics, (e.g., external-bus-to-total-bus ratios, etc.). NERC should clearly define these terms because their potential impact on network modeling decisions.[21] For more discussion of the need to define these terms, please see the Introduction to this report and Section 2.2, Visualization Techniques.

[21] Lack of specificity in these terms was also pointed out in the *FERC Staff Assessment*.

Recommendation – I5

Develop system models and standards for exchange of model information.

Grid Change Notification and Model Data Exchange

The power system models used to provide a wide-area view can require extensive modeling both inside and outside the reliability footprint of an RC or TOP. The external portions of the models are often more difficult to maintain than the internal portions because of the problems related to 1) knowing when something in the grid external to the reliability footprint has changed or is going to change (e.g., a new line or station is added) and 2) being able to obtain required modeling and real-time data from external entities.

As noted in the analysis above related to notification and other procedures among reliability entities, updating of external models is greatly facilitated when there are processes and procedures in place to:

- Prescribe how entities notify each other about pending grid changes far enough in the future to allow updating of real-time network models in a timely manner; and
- Identify the types of data (both real-time and modeling) that are to be exchanged, the time frames for data exchange, acceptable data exchange media and formats, required non-disclosure agreements, etc.

Many survey respondents have at least some data exchange/update processes and procedures in place with entities within their reliability footprints (i.e., their internal model areas), but few if any have such procedures in place for all of the external entities that border and/or have significant impact on their reliability footprints.

RTBPTF recommends that a task force be created to investigate grid change notification and real-time model and ICCP data-exchange processes and procedures. This task force would identify and recommend minimum standards for real-time models and data exchange similar to some of the existing “MOD” standards related to steady-state models (e.g., MOD-010, MOD-011, etc.) but more appropriate for the types of models and supplemental information required by real-time EMS applications such as the state estimator and contingency analysis. The task force should address the following:

- Grid change notification processes and procedures,
- Real-time data exchange (i.e., ICCP data) processes and procedures (a good foundation for these procedures can be found in the documents posted on the NERC DEWG website.)

- Model data exchange processes and procedures (network models and other information needed to support these models such as station schematics, regional maps, etc.), and
- Any required legal agreements needed to facilitate information exchange (non-disclosure, etc.).

External Model Development

It is evident that survey respondents have used a wide range of approaches to create external models and determine what measurements to include in them. Some external models appear to be excessively large and some excessively small, relative to the sizes of the entire models of which they are a part. Some external models contain many real-time analog and status measurements, and some have few or none.

Based on these observations, RTBPTF recommends that a task force be created to focus specifically on external models used to support real-time applications. This task force would be charged with defining guidelines and/or minimum requirements related to external modeling. The areas addressed should include, but are not be limited to:

- The level of external model detail needed to support accurate real-time contingency analysis solutions
- Methods for determining which buses, branches, and other elements to include in an external model for a given internal model
- Methods for determining the real-time analog and status measurements to be included in the external model (i.e., the level of measurement observability)
- Methods for exchanging modeling data and the data-exchange format(s) to use. This includes network model and other supporting information (e.g., station one-line diagrams)
- Methods for maintaining and updating external models
- Identification of tools needed to create and maintain an external model (CIM XML editing tools, model merge tools, reduction/equivalencing tools, etc.).

CIM XML Model Exchange

Based on the Real-time Tools Survey responses and supplemental information collected in follow-up discussions with selected respondents, it appears that some technical issues need to be resolved before the use of power system modeling data contained in CIM XML files becomes commonplace. To date, the few entities that have used CIM XML model dumps in their maintenance activities report in follow-up comments that they have found it to be a challenging exercise. Some current technical issues include:

- Problems are caused by different EMS vendor interpretations of the CIM standard.

- Vendor tools are not always compatible with the exact version of CIM used to create a source model.
- CIM XML files are generally very large. These large files sometimes stress (and sometimes break) the tools that are used to manipulate them.
- Resolving data issues by browsing XML files is difficult because these files cannot easily be read, unlike other model formats such as PSS/E, simple flat files, etc.
- Support tools to manipulate CIM models (e.g., network reduction utilities) are lacking. This is important because most users will not want to incorporate an entire model they receive from another entity (e.g., they may want to strip out the lower voltages).

Despite these and other problems, it is generally believed that CIM XML files will eventually be the preferred format for exchanging power system model data once the major technical issues are addressed.

RTBPTF recommends a review of the current state of CIM XML model exchange to determine in detail where and how this format is being used, identify known problems, and make recommendations about how the industry should proceed with CIM XML model exchange. Short-term model data exchange solutions to use in the interim should also be investigated and identified.

Recommendations for Operating Guidelines

RTBPTF does not recommend developing operating guidelines related to modeling practices and tools.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for modeling practices and tools.

Examples of Excellence

RTBPTF identified no examples of excellence related to modeling practices and tools.

Section 5.0
Support and Maintenance Tools

Introduction

RTBPTF believes that tools and applications for support and maintenance of real-time tools help enhance operator situational awareness. If real-time tools are not supported and maintained, performance measures such as application availability, data integrity, and application solution quality can be compromised without operators knowing. In addition, the equipment (i.e., servers, data links) needed to run real-time tools should be monitored and maintained to preserve the integrity and availability of the real-time tools.

Proper support and maintenance require that support and maintenance personnel have access to the tools/applications that keep real-time tools running. These are also the tools/applications that inform the operator of the availability status of essential real-time tools and thereby contribute to operator situational awareness.

RTBPTF analyzed five support and maintenance tools: display maintenance tools, change management tools and practices, facilities monitoring tools, critical applications monitoring tools, and trouble reporting tools. RTBPTF's analysis and recommendations for each of these tools are presented in Sections 5.1 through 5.5.

Section 5.1, Display Maintenance Tool — A tool/application used by support personnel to develop and maintain power system displays used by operators to monitor, assess, or perform the actions necessary to maintain the reliability of the bulk electric system. Power system displays enhance operator situational awareness.

Section 5.2, Change Management Tools and Practices — Tools/applications used by support personnel to maintain, modify, and/or test critical equipment and/or critical real-time tools[1] that operators use to monitor, assess, or perform the actions necessary to maintain the reliability of the bulk electric system. The practices and processes of support personnel are also discussed this section.

Section 5.3, Facilities Monitoring — Tool/applications that monitor the status of computer systems equipment, servers, backup systems, communications systems, networks, and other critical facilities, etc. This tool allows operators and support personnel to maintain awareness of critical equipment issues that may affect the availability of critical real-time tools used to operate and monitor the bulk electric system.

Section 5.4, Critical Applications Monitoring — Tools/applications that monitor the status of critical real-time tools. These tools allow operators and support personnel to maintain awareness of the availability status of critical real-time tools. Critical real-time tools must be available for operators to monitor, assess, and perform the necessary actions necessary to maintain the reliability of the bulk electric system.

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[1] See the Terminology subsection below for an explanation of the terms "critical equipment" and "critical real-time tools."

Section 5.5, Trouble-Reporting Tool — An application that allows control center tool users (i.e. operators and support personnel) to enter trouble reports (e.g., application problems, system problems, display problems, etc.) so that problems and their resolutions are documented and tracked.

Terminology

RTBPTF introduces two new terms in Section 5 to facilitate discussions and recommendations. The new terms are built on current definitions approved in the NERC Cyber Security Standards, CIP-002 through CIP-009, which were developed by the electric industry to improve the security of cyber assets critical to the reliable operation of the North American bulk electric system. The standards were approved by the NERC BOT on May 2, 2006, and became effective on June 1, 2006. The Cyber Security Standards define the following terms:

- Critical Assets — Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the bulk electric system.
- Cyber Assets — Programmable electronic devices and communication networks including hardware, software, and data.
- Critical Cyber Assets — Cyber assets essential to the reliable operation of critical assets.

RTBPTF introduces the following terms:

- Critical Equipment — Installed equipment that makes up the communication networks, data links, and computer equipment that are directly used as the computer infrastructure for critical real-time tools (see definition below). Critical equipment is essential for reliability entities to ensure the reliable operation of the bulk electric system. Critical equipment is a subset of critical cyber assets (i.e., not all critical cyber assets are considered critical equipment; critical equipment is critical cyber assets that are directly used as the computer infrastructure for critical real-time tools).
- Critical Real-Time Tool — Installed software that is essential (and mandatory) to support, operate, or otherwise interact with bulk electric system operations. Critical real-time tools do not include process control applications or distributed control system applications installed in generating stations, switching stations, or substations.

Significance to the August 14, 2003 Blackout

The support and maintenance tools discussed in this report address some of the issues identified by the August 14, 2003 blackout investigation. Change management tools, facilities monitoring applications, and critical applications monitoring tools enhance operator and support personnel situational awareness. Many of the recommendations for adding new requirements to the existing NERC reliability standards that are presented in the following sections of Chapter 5 relate to these three support and maintenance tools/applications.

The display maintenance tool does not directly support situational awareness; however, it is essential to the creation of power system displays, which are used by operators to enhance their situational awareness. The trouble reporting tool can be used as part of a change management tool to track and document application, system, and display problems and the resolution of each problem. Improper use of each of these tools was cited as a contributing factor to the August 14, 2003 blackout.

Processes for Interactions between Support Personnel and Operators

The lack of situational awareness caused by the failure of support personnel to have or use proper change management tools and practices played a role in the August 14, 2003 blackout. Two failures of this type were identified.

The first failure is identified in a report by the NERC Steering Group (2004):

> FE control center computer support staff did not fully test the functionality of applications, including the alarm processor, after a server failover and restore. After the FE computer support staff conducted a warm reboot of the energy management system to get the failed servers operating again, they did not conduct a sufficiently rigorous test of critical energy management system applications to determine that the alarm processor failure still existed. Full testing of all critical energy management functions after restoring the servers would have detected the alarm processor failure as early as 15:08 and would have cued the FE system operators to use an alternate means to monitor system conditions. Knowledge that the alarm processor was still failed after the server was restored would have enabled FE operators to proactively monitor system conditions, become aware of the line outages occurring on the system, and act on operational information that was received. Knowledge of the alarm processor failure would also have allowed FE operators to warn MISO and neighboring systems, assuming there was a procedure to do so, of the loss of a critical monitoring function in the FE control center computers, putting them on alert to more closely monitor conditions on the FE system.[2]

Because of this deficiency, NERC directed FE to "develop and implement a written procedure describing the interactions between control center technical support personnel and system operators. The procedure shall address notification of loss of critical functionality and testing procedures.[3]" Change management tools and practices would have aided FE in managing this type of support and maintenance issue with its critical reliability tools. A "sufficiently rigorous test" for critical equipment and critical reliability tools is necessary when changes/modifications occur to ascertain the integrity of critical infrastructure and the tools and applications used to maintain the reliability of the bulk electric system.

The second failure was when MISO support personnel analyzed the unacceptably large mismatch produced by its state estimator. The NERC Steering Group report (2004)

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[2] Technical Analysis of the August 14, 2003, Blackout: *What Happened, Why, and What Did We Learn?* 2004. Report to the NERC Board of Trustees by the NERC Steering Group. July 13. p. 96.
[3] Ibid., p. 118.

states, "... the first sign of trouble came at 12:15, when MISO's state estimator experienced an unacceptably large mismatch error between state-estimated values and measured values. The error was traced to an outage of Cinergy's Bloomington-Denois Creek 230-kV line that was not updated in MISO's state estimator. The line status was quickly corrected, but the MISO analyst forgot to reset the state estimator to run automatically every five minutes.[4]" Without proper change management tools and practices, an error such as this failure to reset a critical real-time tool and verify the integrity of the tool with operators, is more likely to occur. Errors of this type can compromise bulk electric system reliability.

As a result of the above deficiency, NERC directed MISO to "reevaluate and improve its communications protocols and procedures with operational support personnel within MISO…[5]" Change management tools and practices would have aided MISO in managing this type of support and maintenance issue with at least one of its critical reliability tools.

Section 5.1 discusses change management tools and practices, and Section 5.5 discusses trouble reporting tools, which can also be viewed as change management tools. The relationship between the two sections is the strong methodology for tying support personnel actions related to critical equipment and critical real-time tools to operator situational awareness; that is, both tools provide a means to communicate to operators any changes made to critical equipment and critical real-time tools, which enhances situational awareness.

Critical Equipment and Critical Real-Time Tools Monitoring

The ability to maintain operator situational awareness of the status of critical equipment and critical real-time tools is an essential component of reliability. NERC Steering Group analysis of the 2003 blackout (2004) states:

> …shortly after 14:14, the alarm and logging system in the FE control room failed and was not restored until after the blackout. Loss of this critical control center function was a key factor in the loss of situational awareness of system conditions by the FE operators. Unknown to the operators, the alarm application failure eventually spread to a failure of multiple energy management system servers and remote consoles, substantially degrading the capability of the operators to effectively monitor and control the FE system...[6]

The document further states that:

> … at 14:41, the primary server hosting the [FE] EMS alarm processing application failed, due either to the stalling of the alarm application, the "queuing" to the remote terminals, or some combination of the two. Following pre-programmed instructions, the alarm system application and all other EMS

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[4] Technical Analysis of the August 14, 2003, Blackout: *What Happened, Why, and What Did We Learn?* 2004. Report to the NERC Board of Trustees by the NERC Steering Group. July 13. p. 28.
[5] Ibid, p. 118.
[6] Ibid, p. 27.

> software running on the first server automatically transferred ("failed-over") onto the back-up server. However, because the alarm application moved intact onto the back-up while still stalled and ineffective, the back-up server failed 13 minutes later, at 14:54. Accordingly, all of the EMS applications on these two servers stopped running… The concurrent loss of two EMS servers apparently caused several new problems for the FE EMS and the system operators using it… although the FE computer support staff should have been aware that concurrent loss of its servers would mean the loss of alarm processing on the EMS, the investigation team has found no indication that the IT staff informed the control room staff either when they began work on the servers at 14:54 or when they completed the primary server restart at 15:08. At 15:42, a member of the computer support staff was told of the alarm problem by a control room operator. FE has stated to investigators that their computer support staff had been unaware before then that the alarm processing sub-system of the EMS was not working.[7]

The above excerpts illustrate the importance of operator and support personnel awareness of the availability status of critical equipment and critical real-time tools. Unavailability of critical equipment and critical real-time tools compromises the reliability of the bulk electric system. In addition, unavailability of critical equipment and critical real-time tools hinders operators' ability to maintain situational awareness.

RTBPTF Recommendations for New Reliability Standards

The NERC Cyber Security Standards address many of the issues related to critical cyber asset security that were identified by the August 14, 2003 blackout investigation. The Cyber Security Standards require that tools and processes be established to ensure that at least minimum security controls are in place to protect critical equipment. However, RTBPTF believes that the Cyber Security Standards do not sufficiently ensure operator situational awareness (i.e., RTBPTF believes that operators must be required to know the availability status of critical equipment and critical real-time tools because these tools are essential to the reliable operation of the bulk electric system).

In the sections that follow, RTBPTF makes several recommendations for modifying the requirements of NERC standard IRO-005. RTBPTF also recommends the development of three operating guidelines and identifies one area requiring additional analysis to support the recommended changes to IRO-005. In addition, the task force identifies eight entities whose use of support and maintenance tools can be considered examples of excellence within the industry.

Specifically, RTBPTF recommends that:

- Each RC and TOP be required to identify critical equipment (in a Critical Equipment Identification Document) that it uses to monitor the bulk electric system and maintain awareness of critical equipment status to ensure that

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[7] Page 33-34 of the "Technical Analysis of the August 14, 2003, Blackout: What Happened, Why, and What Did We Learn?" document

unavailability of critical equipment does not impair the reliable operation of the bulk electric system.

- Each RC and TOP be required to include, at a minimum,
    - The following list of critical real-time tools used in the operation and monitoring of the bulk electric system: alarm tools, telemetry data systems (including applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.
    - The following list of critical equipment used in the operation and monitoring of the bulk electric system: servers or computers that contain the critical real-time tools specified above and the data links that provide the input to the critical real-time tools specified above.
- Each RC and TOP be required to maintain a Critical Equipment Monitoring Document identifying its tools and procedures for monitoring critical equipment (including critical real-time applications) and notifying operators when critical equipment is unavailable.
- Each RC and TOP be required to implement automated tools or organizational processes to monitor critical equipment (which includes critical real-time applications) and related system events to ensure reliable operation of the bulk electric system.
- Each RC and TOP be required to maintain event logs pertaining to critical equipment (which includes critical real-time applications) status for a period of one year.
- Each RC and TOP be required to maintain a Critical Equipment Maintenance and Testing Document identifying its tools and procedures for maintenance, modification, and testing of critical equipment.

RTBPTF also proposes measures for the requirements recommended for Standard IRO-005-1.

Section 5.1
Display Maintenance Tool

Definition

Support personnel use the display maintenance tool to develop and maintain visual interfaces that operators use to maintain situational awareness, i.e., to monitor and assess bulk electric system reliability and/or take action to maintain system reliability.

Background

Displays are human-machine interface (HMI) views that allow operators to monitor, assess, or perform necessary actions to maintain the reliability of the bulk electric system during normal and emergency operations. Displays usually present visual representations of power system elements and other application data; this information is the basis for operator situational awareness. Although not a real-time tool, the display maintenance tool is critical for support personnel to keep visual interfaces operational.

Summary of Findings

The majority (96 percent) of respondents to the display maintenance tool section of the Real-Time Tools Survey have an operational display maintenance tool that offers the functionality defined in the survey. The overwhelming majority (94 percent) of all respondents that have an operational display maintenance tool rated it “essential” for situational awareness. Not one entity rated the application as of “minimal” or of “no value.” One respondent notes that “without a display maintenance tool, there would be no way to build supporting displays.” Table 5.1-1 shows the breakdown of the ratings.

NOTE: In the columns of all tables in this section that list percentages of respondents, the percentage value is preceded by the number of respondents out of the total that gave the indicated response. For example, “32/38=84%” means that 32 out of a total of 38 respondents, or 84% of respondents, gave the indicated response.

Respondent Type	How do you Rate the Value of Your Display Maintenance Tool as a Critical Support Tool to Enhance Reliability Operation and Situational Awareness?	
	“Essential”	“Desirable”
All	29/31=94%	2/31=6%
RC	13/13=100%	0/0=0%
Others	16/18=89%	2/18=11%

Table 5.1-1 — Value of Display Maintenance Tool

Although respondents consistently rate the application as an essential support tool, they report significant variation in its implementation and usage.

Power System Displays

Most power system displays built for operators present SCADA measurements/telemetry data from the field. Most respondents indicate that they use power system displays that contain the state estimator or operator power-flow application solution (see Table 5.1-2). This is common industry practice: to leverage display of SCADA measurements to represent equivalent state estimator or operator power-flow solutions. Some entities use the same power system representation for their DTS application as well as their outage scheduler application. The most widely used types of power system displays are:

- One-Line Displays — visually represent a substation (transmission or distribution) and its corresponding power system elements. Discussed extensively in Section 2.2, Visualization Techniques.
- Transmission-Line Circuit Displays — visually represent the circuit connectivity of transmission substations to adjacent transmission substations; the distribution substations between two transmission substations are also often represented.
- Transmission Overview Displays — show a wide-area view of a transmission grid. Could also be referred to as dynamic overview displays or wide-area visualization displays (depending on usage). Discussed extensively in Section 2.2, Visualization Techniques.

One-Line Displays			
Type	**All**	**RC**	**Others**
SCADA	31//31=100%	12/12=100%	19/19=100%
State Estimator	27/31=87%	12/12=100%	15/19=79%
Power Flow	27/31=87%	12/12=100%	15/19=79%
DTS	17/31=55%	8/12=67%	9/19=47%
Outage Scheduler	3/31=10%	1/12=8%	2/19=10%
Transmission-Line Circuit Displays			
Type	**All**	**RC**	**Others**
SCADA	25/29=86%	10/12=83%	15/19=79%
State Estimator	26/29=90%	11/12=92%	15/19=79%
Power Flow	25/29=86%	10/12=83%	15/19=79%
DTS	14/29=48%	7/12=58%	7/19=37%
Outage Scheduler	3/29=10%	1/12=8%	2/19=10%
Transmission Overview Displays			
Type	**All**	**RC**	**Others**
SCADA	28/31=90%	11/12=92%	17/19=89%
State Estimator	22/31=71%	9/12=75%	13/19=68%
Power Flow	21/31=68%	9/12=75%	12/19=63%
DTS	14/31=45%	6/12=50%	8/19=42%
Outage Scheduler	2/31=6%	1/12=8%	1/19=5%

Table 5.1-2 — Power System Displays

Display Validation

Power system displays are critical visual representations of the monitored electric system, so the accuracy of display information is of great importance. The Real-Time Tools Survey asked respondents for a free-form description of the methods used to validate their displays. Respondents described the following methods:

- Display Testing — Displays are tested initially from a development system before being loaded into the operational system. Validation includes error checking and functional testing to ensure that displays will not harm the operational system. Links between displays and operational data are checked to be sure they are accurate and working correctly.
- Data Accuracy Checks — Despite a wide range of tools available for checking display problems, display accuracy is commonly checked manually by comparison to paper diagrams.

Noteworthy Functional Features

The survey results reveal that display maintenance tools are widely used and considered essential. The survey did not quantify their effectiveness; however, it is clear that accurate displays and detection of display errors enhance situational awareness. Many entities use multiple tools and practices to support display maintenance for various applications and systems, including wide-area overview displays and mapboards. RTBPTF believes these findings could help entities improve and benchmark their current display maintenance processes through self assessment. The following is a list of functional features deemed “essential” (based on ratings by a significant majority of survey respondents) to enhance situational awareness:

- Automatic Display Generator for Power System Displays — Enable an application to automatically generate power system displays from a single display. For example, from a SCADA station one-line display, the state estimator, power flow, etc. station one-line displays can be generated. Without this feature, support personnel would have to manually create the other power system displays. Manually creating displays could introduce errors and inconsistency; creating similar displays using a program could mitigate this problem. Forty-nine percent of respondents have an operational version of this feature. Of the entities that have this operational feature, 71 percent rate it “essential,” 14 percent as “desirable,” and 14 percent as of “minimal value” for situational awareness.
- Bad Display Link Indicator — Allows an application to automatically generate a summary of incorrect display linkages for telemetered data for multiple displays that use a given link. This feature signifies that the data being presented may be inaccurate. Forty-one percent of survey respondents have an operational version of this feature. Of the entities that have this feature operational, 92 percent rate it as “essential,” and 8 percent rate it as “desirable” for situational awareness.

Recommendations for New Reliability Standards

RCs, TOPs, and BAs depend on the availability and accuracy of displays to operate the bulk electric system in a coordinated manner so that it performs reliably under normal and abnormal conditions, as defined in NERC standards. The Real-Time Tools Survey responses reveal significant variation in display maintenance practices; the industry as a whole has no cohesive method of maintaining displays for operator use. The display maintenance tool indirectly affects bulk electric system reliability, but the availability and accuracy of the displays designed and created using this tool directly affects system reliability. These displays are discussed in Section 2.2, Visualization Techniques. RTBPTF has no recommendations for new reliability standards for the display maintenance tool.

Recommendations for Operating Guidelines

Because RTBPTF recommends no reliability standards related to display maintenance tools, it also has no recommendations for operating guidelines.

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for display maintenance tools.

Examples of Excellence

RTBPTF cites the California Mexico RC's use of a display maintenance tool application to ensure that its energy management system displays are functioning properly as an example of excellence (See EOE-17 in Appendix E).

Section 5.2
Change Management Tools and Practices

Definition

Support personnel use change management tools and practices to maintain, modify, and/or test critical equipment[8] that operators use to monitor and perform necessary actions to maintain reliability of the bulk electric system.

Background

The availability and integrity of critical equipment in control centers directly affect reliability. Therefore, the tools and practices used to maintain, modify, and test critical equipment — usually called change management tools and practices – are directly related to reliability. Support personnel must use proper change management tools and practices to avoid disruptions in the function or availability of critical equipment that could affect operators' situational awareness.

The *Outage Task Force Final Blackout Report* notes that, as part of the events related to the August 2003 blackout, FE support personnel rebooted servers that had a failed alarm module without checking with control room staff/operators to confirm that all applications were running properly. In another event related to the blackout, MISO support personnel left software in a manual operation mode after solving a state estimator mismatch. These two examples signify a deficiency in change management tools and practices. On each occasion, the problem could have been averted if proper maintenance and testing procedures had been in place. In FE's case, effective change management tools and practices would have required that personnel check with the operators to find out whether the alarm tools application problem was resolved after the module reboot. In MISO's case, effective change management tools and practices would have required verification that the state estimator was running in a condition that allowed the operator to use it, so the application would not have been left in manual mode.

In short, failure of support personnel to use appropriate change management tools and practices played a role in the August 14, 2003 blackout. Causal analysis in the *Outage Task Force Final Blackout Report* reveals the following deficiencies:

> Cause 1c: FirstEnergy control center computer support staff did not fully test the functionality of applications, including the alarm processor, after a server failover and restore.

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[8] For the purposes of this discussion, *critical equipment* is defined as installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools. Critical equipment is a subset of critical cyber assets. *Critical real-time tools* are defined as installed software that is essential to support, operate, or otherwise interact with bulk electric system operations. All reliability entities (not just RCs) need critical equipment and real-time tools to ensure reliable operation of the bulk electric system.

The Corrective Actions section of the *Outage Task Force Final Blackout Report* recommends:

g. Technical Support. FirstEnergy shall develop and implement a written procedure describing the interactions between control center technical support personnel and system operators. The procedure shall address notification of testing procedures and loss of critical functionality.[9]

Summary of Findings

The Real-time Tools Best Practices Survey was designed to examine current tools and practices in software (rather than hardware) maintenance, modification, and testing. Most survey respondents (78 percent) have operational software maintenance tools. They also indicate that they have maintenance, modification, and testing practices. The majority (77 percent) of all respondents that have operational software maintenance tools rate these tools as "essential" for situational awareness; a minority (23 percent) rate their tools "desirable" for situational awareness. Not one entity rates its tools as of "minimal value" or "no value" for situational awareness. One respondent states that "it is essential for support personnel to have a quick method to access the source code of critical/core applications in case there is an issue that requires code repairs. This access needs to be controlled so that the operational environment is not affected when code is compiled and loaded into the operational system." This majority percentage was consistent across all entity types except BAs (see Table 5.2-1).

Entity Type	How do You Rate the Value of Your Software Maintenance Tools and Practices as a Critical Support Tool to Enhance Reliability Operation and Situational Awareness?	
	"Essential"	"Desirable"
All	27/35=77%	8/35=23%
RCs	12/16=77%	4/16=23%
Others	15/19=79%	4/19=21%

Table 5.2-1 — Value of Software Maintenance Tools

The survey results also reveal that most entities (97 percent) that have operational software maintenance tools also have source codes on hand for their reliability tools/applications. Most entities (91 percent) indicate that their support staff can modify (when necessary) the source codes of their reliability tools/applications.

[9] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April.

Practices/Processes Related to Software Maintenance Tools

Most entities (85 percent) that have operational software maintenance tools have some form of code control process, i.e., a software (source code) change management process, such as version control, change tracking, or user management and administration. The majority of entities (81 percent) that have this process/tool available rate it "essential" for enhancing situational awareness.

Most entities (76 percent) that have operational software maintenance tools do not have the ability to notify (via paging) software support personnel if new software is loaded on-line. This question was included in the survey because RTBPTF believes this type of notification enhances situational awareness of support personnel when certain applications are being updated online.

Recommendations for New Reliability Standards

To ensure proper maintenance, modification, and testing, RTBPTF recommends that new requirements for change management tools and practices be added to existing standard IRO-005 (Reliability Coordination – Current Day Operations) to strengthen operator situational awareness. RTBPTF recommends adding the change management requirements to the reliability coordination current day operations standard rather than the cyber security standards because the latter focus primarily on protecting and securing critical cyber assets; specifically, Standard CIP-003 requires that responsible entities have minimum security management controls in place to protect critical cyber assets. The cyber security standards do not, however, explicitly address operator situational awareness of critical equipment that may affect the reliable operation of the bulk electric system.

Change management requirements could, in principle, also be added to NERC's cyber security standards CIP-002 through CIP-009, which specifically address change control and configuration management for software and hardware maintenance. Standard CIP-003 (Cyber Security – Security Management Controls), Requirement 6, states that "the Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control, and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process." The cyber security standards require that tools and processes be established so that minimum security controls are in place to protect critical equipment.

However, RTBPTF recommends adding the change management requirements to Standard IRO-005 because operator awareness of the status of critical equipment (which is directly related to critical equipment maintenance, modification, and testing processes) is essential to the RC's continuous awareness of conditions that may impair the operator's ability to operate the bulk electric system reliably. RTBPTF recommends that a new requirement be added to IRO-005 to require RCs and TOPs to implement automated tools or organizational processes to monitor critical equipment availability, including the activities related to critical equipment maintenance, modification, and testing.

RTBPTF Recommendation

The requirements recommended for addition to existing Standard IRO-005 are stated below.[10] The full text of interrelated requirements applicable to critical equipment, which comprises three areas, (change management tools and practices, facilities monitoring (Section 5.3), and critical applications monitoring (Section 5.4)) is presented here for clarity. The requirements related to the topic of this section of the report, change management tools and practices, are highlighted in italic font.

PR1. Each reliability coordinator and transmission operator shall monitor and maintain awareness of critical equipment status to ensure that the unavailability of critical equipment does not impair the reliable operation of the bulk electric system. Other entities supporting or complementing the reliability coordinator's or transmission operator's ability to operate the bulk electric system reliably shall be subject to the same requirements as the reliability coordinator or transmission operator respectively.

PR1.1. Identification of critical equipment — Each reliability coordinator and transmission operator shall identify the critical equipment it uses for bulk electric system operation and monitoring. This includes the critical equipment of parties to whom the reliability coordinator or transmission operator has delegated reliability functions. Each reliability coordinator and transmission operator shall maintain a Critical Equipment Identification Document that lists all critical equipment. The Critical Equipment Identification Document shall be kept current at all times.

PR1.1.1. Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical real-time tools used in the operation and monitoring of the bulk electric system: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.

PR1.1.2. Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical equipment used in the operation and monitoring of the bulk electric system: servers or computers that contain the critical real-time tools specified above and the data links that provide the input to the critical real-time tools specified above.

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[10] Proposed requirements are designated "PR," and proposed measures are designated "PM."

Recommendation – S37

Maintain a Critical Equipment Monitoring Document to identify tools and procedures for monitoring critical equipment.

PR1.2. *Monitoring of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Monitoring Document identifying its tools and procedures for monitoring critical equipment (which includes critical real-time applications). This document shall describe how to verify that the tools and procedures are functioning and being used as intended. This document shall describe the tools and procedures for operator notification when critical equipment is unavailable*.

PR1.2.1. *Each reliability coordinator and transmission operator shall implement automated tools or organizational processes to monitor critical equipment (which includes critical real-time applications) and related system events to ensure reliable operation of the bulk electric system. These tools or organizational processes shall be described in the Critical Equipment Monitoring Document.*

Recommendation – S38

Maintain event logs pertaining to critical equipment status for a period of one year.

PR1.3. *Each reliability coordinator and transmission operator shall maintain event logs pertaining to critical equipment (which includes critical real-time applications) status for a period of one year. At a minimum, the event logs shall contain the following information regarding any event that affects the functionality and/or availability of critical equipment. The event log shall address the following questions: What happened? When did it happen? Who was notified? What was the resolution?*

Recommendation – S39

Maintain a Critical Equipment Maintenance and Testing Document identifying tools and procedures for maintenance, modification, and testing of critical equipment.

PR1.4. *Maintenance of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Maintenance and Testing Document identifying its tools and procedures for maintenance, modification, and testing of critical equipment. This document shall describe how to verify that the tools and procedures are functioning and being used as intended*.

RTBPTF recommends the following measures for the requirements stated above. The measures related to change management tools and practices are written in italic font.

PM 1. Measures for Critical Equipment Monitoring

PM 1.1 The Critical Equipment Identification Document must be available as specified in Requirement PR1.1. Additionally, each reliability coordinator and transmission operator shall demonstrate that the Critical Equipment Identification Document is kept current at all times.

PM 1.1.1. As specified in Requirement PR1.1.1, the Critical Equipment Identification Document must contain, as part of its list of critical real-time applications, the following applications: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.

PM 1.1.2. As specified in Requirement PR1.1.2, the Critical Equipment Identification Document must contain, as part of its list of critical equipment, the following equipment: servers or computers that contain the critical real-time tools, and the data links that provide the input to the critical real-time tools specified.

PM 1.2 *The Critical Equipment Monitoring Document must be available as specified in PR1.2. Additionally, each reliability coordinator and transmission operator must demonstrate that the Critical Equipment Monitoring Document is kept current at all times and that the documented tools/procedures are used as intended*.

PM 1.2.1. *Each reliability coordinator and transmission operator must demonstrate, upon request, its capability to monitor critical equipment via automated tools (e.g., critical equipment status displays or visualization tools) or organizational processes (e.g., trouble* *notification processes) as stated in Requirement PR1.2.1.*

PM 1.3 *Each reliability coordinator and transmission operator must demonstrate that the event logs as stated in Requirement PR1.3 contain the required information*.

PM 1.4 *The Critical Equipment Maintenance and Testing Document must be available as specified in PR1.4.*

Rationale

The "Purpose" section of Standard IRO-005 states, "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas." RTBPTF believes that operator awareness of the status of critical equipment (which is directly related to critical equipment maintenance, modification, and testing processes) is essential to the reliability coordinator's continuous awareness of conditions that may impair the operator's ability to operate the bulk electric system reliably. Therefore, the change management requirements for critical equipment maintenance, modification, and testing should be included as part of this standard. Other entities supporting or complementing the RC's ability to operate the bulk electric system reliably must be subject to the same requirements as the RC. As noted in the Summary of Findings section above, the *Outage Task Force Final Blackout Report* notes that the lack of strong change management tools and practices contributed to the lack of operator situational awareness related to the August 2003 blackout*.*

RTBPTF includes TOPs in the recommendations stated above because these entities are subject to the Reliability Toolbox requirement.[11]

Recommendations for Operating Guidelines

RTBPTF recommends development of the following operating guidelines for change management tools and practices. These operating guidelines support the recommended additional requirements to Standard IRO-005-1 stated above.

- Each reliability coordinator should have a demonstrated change management process for performing critical equipment maintenance, modification, and testing. This change management process should have the objective/purpose of ensuring the availability and integrity of critical equipment. The change management process should, at a minimum, include the following:
    - Management, operator, and support personnel notification and approval for production system changes
    - Pre- and post-production testing of system installation testing

[11] See the Reliability Tool Box Rationale and Recommendation section as well as the specific recommendations for each tool in the Reliability Toolbox.

- Personnel authorization and security
- System source code backup and recovery

- Each reliability coordinator should have a change management tool that has, at a minimum, the following capabilities:
  - Audit logging of all activities (modifications, additions, deletions, etc.) related to all source code files
  - Version control with the ability to roll back to an earlier version

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for change management tools and practices.

Examples of Excellence

RTBPTF cites PJM's use of a feature management system that provides audit logging and version control capabilities as an example of excellence (See EOE-18 in Appendix E). The approach taken by PJM ensures that software modifications do not compromise the availability and integrity of their critical real-time applications that support operator situational awareness

Section 5.3
Facilities Monitoring

Definition

The facilities monitoring application tracks the status of computer systems equipment, servers, backup systems, communications systems, networks and other critical facilities. This tool allows operators and/or support personnel to be aware of critical equipment issues that may affect the availability of critical real-time tools used to operate and monitor the bulk electric system.

Background

As discussed in detail in Section 5.0, Support and Maintenance Tools, situational awareness of the status of critical equipment, which includes facilities such as computer systems equipment, servers, backup systems, communications systems, networks and other critical facilities in the control center, is an essential component directly related to reliability. The *Outage Task Force Final Blackout Report* states that FE's operators were unaware of the failure and the concurrent loss of two EMS servers that apparently caused several new problems for the FE EMS and the operators using it. This illustrates the importance of having monitoring tools that report unavailability of critical equipment. Operators need to be aware when their ability to monitor the bulk electric system is compromised. Proper notification of maintenance and support personnel is requisite for real-time operations.

The operator has to have keen awareness of the status and availability of critical equipment. This includes critical equipment that is used as a backup to primary critical equipment. The operator could have no provision for monitoring the bulk electric system if a critical piece of equipment is unavailable or not working correctly. Critical real-time tools depend on critical equipment, and a facilities monitoring application allows for operators to be aware of the status and availability of critical equipment, which enhances operator situational awareness.

Summary of Findings

The majority of respondents (86 percent) have an operational facility monitoring application that offers the same functionality as defined in the Real-Time Tools Survey. Interestingly, all RCs report having an operational facilities monitoring application. For respondents that have an operational facilities monitor, the majority (84 percent) rate this application "essential" for situational awareness while 16 percent rate it "desirable." Not one entity rates the application as of "minimal value" or "no value" for situational awareness. One of the respondents states that "any information as to the 'state of the operational system' is a key indicator for situational awareness. For system support personnel, maintaining situational awareness of key infrastructure equipment is analogous to maintaining situational awareness of bulk power system elements." Table 5.3-1 summarizes the survey results.

Entity Type	How do You Rate the Value of Your EMS Facilities Monitor as a Critical Support Tool to Enhance Reliability Operation and Situational Awareness?	
	"Essential"	**"Desirable"**
All	32/38=84%	6/38=16%
RC	13/15=84%	2/15=16%
Others	19/23=83%	4/23=17%

Table 5.3-1 — Value of Facilities Monitor Application

These data suggest that the majority of respondents consider the facilities monitor an essential operational support tool. Because the survey results reveal a significant variation in practice, implementation, and use of this application, it is a logical candidate for some degree of standardization.

The survey asked respondents to identify the types of equipment/facilities that are monitored. A majority of respondents monitor the status of their critical servers, voice/data communication links, internal networks, and backup facilities listed (see Table 5.3-2).

Equipment	All	RC	Others
Status of Critical Servers	38/38=100%	15/15=100%	23/23=100%
Mapboard (Hardware Status) Availability	20/38=53%	11/15=73%	9/23=39%
Voice/Data Communication Links	33/38=87%	13/15=87%	20/23=87%
Internal Communication Network(s)	29/38=76%	12/15=80%	17/23=74%
RTU Status	20/38=79%	11/15=73%	9/23=39%
Availability of Backup System	33/38=87%	13/15=87%	20/23=87%
Power Supply (UPS)	26/38=68%	13/15=87%	13/23=56%
Power Supply (Backup Generators)	24/38=63%	12/15=80%	12/23=52%
Batteries	20/38=53%	10/15=67%	10/23=43%
Heating, ventilation, and air conditioning	15/38=39%	7/15=47%	8/23=35%
Fire Protection Systems	15/38=39%	7/15=47%	8/23=35%

Table 5.3-2 — Equipment/facilities Monitored Using Facilities Monitoring Application, by Entity Type

The survey reveals that entities monitor equipment that is essential to the continuing operation of their control centers. This encouraging result shows that monitoring of critical equipment is a prevailing industry practice. Awareness of critical equipment status supports situational awareness. Critical equipment monitoring tells operators what equipment is available or unavailable, which allows operators to determine whether the capability of these tools is degraded by critical equipment problems.

The survey also examined the functional features of facilities monitoring applications. Ninety-seven percent of respondents report that their facilities monitors interface directly with their alarm tools applications and can generate critical equipment status alarms. Of the entities that use this feature, 86 percent rated it “essential” for situational awareness. These data suggest that an interface between the facilities monitor and the alarm tools enhances situational awareness.

Operators at most entities (87 percent) have access to a visual representation of critical equipment status. Seventy-three percent of entities that have this feature rate it "essential" for situational awareness, 24 percent rate this feature "desirable," and 3 percent rate it as having "minimal value." These data suggest that a visual representation of critical equipment status enhances operator situational awareness.

Many entities (56 percent) have a system that pages support personnel when the facilities monitor indicates that a critical equipment status is unavailable. Fifty-five percent of entities that have this functional feature rate it "essential" for situational awareness, 40 percent rate it as "desirable," and 5 percent rate it as having "minimal value." These data suggest that an interface between the facilities monitor and a paging system enhances operator situational awareness.

Insufficient data were collected to properly evaluate the usage and implementation of the respondents' facilities monitor applications. Ideally, to ascertain critical equipment status, the application should be independent of the equipment being monitored. Further exploration is needed to determine whether this strategy is used in the industry. More data are also needed on the methodology used to declare critical equipment "unavailable."

Recommendations for New Reliability Standards

Because continual monitoring of the availability of critical equipment/critical real-time tools is essential for reliable power system operation, as indicated by the survey results, RTBPTF recommends adding new facilities monitoring requirements to existing standard IRO-005 (Reliability Coordination – Current Day Operations), to strengthen operator situational awareness.

Facilities monitoring requirements could, in principle, also be added to NERC's cyber security standards CIP-002 through CIP-009, which address securing of critical cyber assets and require that tools and processes be established so that minimum security controls are in place to protect critical equipment. Specifically, Standard CIP-007, Requirement 6 mandates that the responsible entity ensure that all cyber assets within the electronic security perimeter, to the degree technically feasible, implement automated tools or organizational process controls to monitor system events related to cyber security. However, Standard CIP-007 does not explicitly address operator situational awareness of critical equipment that may affect the reliable operation of the bulk electric system; rather it focuses on automated tools or organizational process controls to monitor system events related to cyber security only. Therefore, the RTBPTF recommends adding the facilities monitoring requirements to Standard IRO-005. This standard is a more appropriate location for the requirements because the purpose of IRO-005 is operator awareness of bulk electric system parameters.

RTBPTF Recommendation

The requirements recommended for addition to existing Standard IRO-005 are stated below. The full text of interrelated requirements applicable to critical equipment, which comprises three areas, (change management tools and practices (Section 5.2), facilities monitoring, and critical applications monitoring (Section 5.4)) is presented here for clarity. The requirements related to the topic of this section of the report, facilities monitoring, are highlighted in italic font.

Recommendation – S40

Monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation.

PR1. *Each reliability coordinator and transmission operator shall monitor and maintain awareness of critical equipment status to ensure that the unavailability of critical equipment does not impair the reliable operation of the bulk electric system. Other entities supporting or complementing the reliability coordinator's or transmission operator's ability to operate the bulk electric system reliably shall be subject to the same requirements as the reliability coordinator or transmission operator respectively.*

PR1.1. *Identification of critical equipment — Each reliability coordinator and transmission operator shall identify the critical equipment it uses for bulk electric system operation and monitoring. This includes the critical equipment of parties to whom the reliability coordinator or transmission operator has delegated reliability functions. Each reliability coordinator and transmission operator shall maintain a Critical Equipment Identification Document that lists all critical equipment. The Critical Equipment Identification Document shall be kept current at all times.*

PR1.1.1. Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical real-time tools used in the operation and monitoring of the bulk electric system: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.

PR1.1.2. *Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical equipment used in the operation and monitoring of the bulk electric system: servers or computers that contain the critical real-time tools specified above and* *the data links that provide the input to the critical real-time tools specified above.*

PR1.2. *Monitoring of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Monitoring Document identifying its tools and procedures for monitoring critical equipment (which includes critical real-time applications). This document shall describe how to verify that the tools and procedures are functioning and being used as intended. This document shall describe the tools and procedures for operator notification when critical equipment is unavailable.*

PR1.2.1. Each reliability coordinator and transmission operator shall implement automated tools or organizational processes to monitor critical equipment (which includes critical real-time applications) and related system events to ensure reliable operation of the bulk electric system. These tools or organizational processes shall be described in the Critical Equipment Monitoring Document.

PR1.3. Each reliability coordinator and transmission operator shall maintain event logs pertaining to critical equipment (which includes critical real-time applications) status for a period of one year. At a minimum, the event logs shall contain the following information regarding any event that affects the functionality and/or availability of critical equipment. The event log shall address the following questions: What happened? When did it happen? Who was notified? What was the resolution?

PR1.4. Maintenance of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Maintenance and Testing Document identifying its tools and procedures for maintenance, modification, and testing of critical equipment. This document shall describe how to verify that the tools and procedures are functioning and being used as intended.

RTBPTF recommends the following measures for the requirements stated above. The measures related to change management tools and practices are written in italic font.

PM 1. *Measures for Critical Equipment Monitoring*

PM 1.1 *The Critical Equipment Identification Document must be available as specified in Requirement PR1.1. Additionally, each reliability coordinator and transmission operator shall demonstrate that the Critical Equipment Identification Document is kept current at all times.*

PM1.1.1. As specified in Requirement PR1.1.1, the Critical Equipment Identification Document must contain, as part of its list of critical real-time applications, the following applications: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.

PM1.1.2. *As specified in Requirement PR1.1.2, the Critical Equipment Identification Document must contain, as part of its list of critical equipment, the following equipment: servers or computers that contain the critical real-time tools, and the data links that provide the input to the critical real-time tools specified.*

PM 1.2 *The Critical Equipment Monitoring Document must be available as specified in PR1.2. Additionally, each reliability coordinator and transmission operator must demonstrate that the Critical Equipment Monitoring Document is kept current at all times and that the documented tools/procedures are used as intended*.

PM1.2.1. Each reliability coordinator and transmission operator must demonstrate, upon request, its capability to monitor critical equipment via automated tools (e.g., critical equipment status displays or visualization tools) or organizational processes (e.g., trouble notification processes) as stated in Requirement PR1.2.1.

PM 1.3 Each reliability coordinator and transmission operator must demonstrate that the event logs as stated in Requirement PR1.3 contain the required information.

PM 1.4 The Critical Equipment Maintenance and Testing Document must be available as specified in PR1.4.

Rationale

The "Purpose" section of Standard IRO-005 states, "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas." RTBPTF believes that information on critical equipment status is essential to the RC's continuous awareness of conditions that may impair the RC's ability to operate the bulk electric system reliably. Lack of awareness that critical equipment was unavailable was a significant element contributing to the August 14, 2003 Blackout, as noted in the *Outage Task Force Final Blackout Report*. If a new requirement is not established for monitoring of critical equipment, there will be no way to ensure that operators are aware when critical equipment, such as servers, is unavailable.

RTBPTF included TOPs in the recommendation above because these entities are subject to the recommended Reliability Toolbox requirement and are required to have the critical equipment that provides the infrastructure for the Reliability Toolbox tools.[12]

Recommendation – G13

Establish a change management process for performing critical equipment maintenance, modification, and testing.

Recommendations for Operating Guidelines

RTBPTF recommends development of the following operating guidelines for the facilities monitor application. These operating guidelines support the recommended additional requirements to Standard IRO-005-1 stated above.

Recommendation – G14

Develop a notification process when critical equipment is unavailable and an analysis/resolution process for critical equipment failures.

- Each reliability coordinator should have a demonstrated critical equipment monitoring process. This monitoring process should have the objective/purpose of enhancing operator awareness of the availability of critical equipment. The monitoring process should, at a minimum, include:
  - Notification of management, operator, and support personnel when critical equipment is unavailable
  - An analysis and resolution process for critical equipment failures

[12] See the Reliability Toolbox Rationale and Recommendation section as well as the recommendations for each tool in the Reliability Toolbox.

Recommendation – G15

Develop a critical monitoring application that interfaces to alarm tools and logs all events related to the equipment failures.

- Each reliability coordinator should have a facilities monitoring application, which has, at a minimum, the following capabilities:
  - Interface of facilities monitoring application to alarm tools
  - Audit logging of all events related to critical equipment failures

Areas Requiring More Analysis

RTBPTF identified no areas requiring additional analysis for facilities monitoring.

Examples of Excellence

RTBPTF cites American Electric Power's use of a facilities monitor application by Central and Southwest (CSWS) as an example of excellence (See EOE-19 in Appendix E). CSWS interfaces their facilities monitoring application with their critical applications monitor application.

Section 5.4
Critical Applications Monitoring

Definition

The critical applications monitor tracks the status of critical real-time tools. This application allows operators and/or support group personnel to track availability of critical real-time tools. Critical real-time tools must be available for operators to monitor, assess, and perform the necessary actions to maintain the reliability of interconnected bulk electric systems. A critical applications monitor tool may be part of a facilities monitoring tool (see Section 5.3, Facilities Monitoring).

Background

As discussed in detail in Section 5.0, Support and Maintenance Tools, situational awareness of the status and availability of critical real-time tools is an essential component directly related to reliability. The Outage Task Force Final Blackout Report stated that FE's computer support staff was unaware of the failure of their alarm tools application. FE had no alarm tools failure detection system. When the FE alarm processor stopped functioning properly, computer support staff remained unaware of this failure until a second EMS server failed approximately 40 minutes later. Because FE had no periodic diagnostics to evaluate and report the state of their alarm tools, support staff were not alerted to the eventual failure of two EMS servers or the infinite loop lockup failure of the alarms — or that the alarm processor had failed in this manner earlier and independently of the server failures. This illustrates the importance of having monitoring tools that report unavailability of critical real-time tools. Operators need to be aware when their ability to monitor the bulk electric system has degraded. Proper notification of maintenance and support personnel is requisite for real-time operations.

Summary of Findings

All respondents to the critical applications monitor portion of the Real-Time Tools Survey indicate that they have an operational critical applications monitor tool that offers the same functionality as defined in the survey. Additionally, all respondents rate their critical applications monitor as either “essential” or “desirable” for situational awareness. The majority (88 percent) rate it “essential,” and not one entity rates it having “minimal value” or “no value.” One respondent states that “this tool has dramatically improved… state estimator availability and…ICCP data availability.” This majority rating was consistent across all entity types, as shown in Table 5.4-1.

Entity Type	How do You Rate the Value of Your EMS Critical Applications Monitor as a Critical Support Tool to Enhance Reliability Operation and Situational Awareness?	
	"Essential"	"Desirable"
All	35/40=88%	5/40=12%
RC	13/15=87%	2/15=13%
Others	22/25=88%	3/25=12%

Table 5.4-1 — Value of Critical Applications Monitor, by Entity Type

The survey results reveal that, although the majority of respondents consider the critical applications monitor tool essential, there is a significant variation in practice, implementation, and usage of the tool. Therefore, this tool is a logical candidate for standardization. The survey asked respondents to identify the types of critical applications that are monitored by their organizations. A consistent majority of respondents monitored the critical applications listed in the survey (see Table 5.4-2). Other entities also monitor automatic generation control (AGC) and market applications.

Applications	All	RC	Others
Alarm Tools	36/40=90%	12/15=80%	24/25=96%
State Estimator	28/40=70%	13/15=87%	15/25=60%
Contingency Analysis	25/40=63%	12/15=80%	13/25=52%
SCADA	37/40=93%	13/15=87%	24/25=96%
Inter-Utility Link Data Application	33/40=83%	12/15=80%	21/25=84%

Table 5.4-2 — Applications Tracked by Critical Applications Monitor, by Entity Type

The survey results indicate that the majority of entities have tools and processes to monitor applications that are critical to continuous operation of their control centers. This encouraging result shows that critical applications monitoring is a prevailing industry practice. Critical applications monitoring is important not only for computer support but also for reliable operation of the bulk electric system. Increasing operator awareness of critical real-time tool status increases situational awareness.

The survey also examines the functional features of critical applications monitor applications. All of the respondents can generate alarms based on critical real-time tools status, and the critical applications monitor interfaces directly to the alarm tools application. Of the entities that use this functional feature (interface to alarm tools), 82 percent rate it “essential” for situational awareness. These data suggest that situational awareness is enhanced if the critical applications monitor interfaces with the alarm tools application.

Operators at 72 percent of entities responding to the survey have access to visual representation of critical real-time tools status. Entities that have this functional feature rate it either “essential” (59 percent) or “desirable” (41 percent) for situational awareness. Entities that do not have this feature rate it “desirable” (73 percent) or of “minimal value” (18 percent), or “no value” (9 percent). These results indicate that a majority of the industry believes that visual representation of critical real-time tools status can enhance operator and support staff situational awareness.

Table 5.4-3 shows the percentages of respondents that have a critical applications monitor tool that can page support personnel when a critical real-time application is unavailable or stalled. Entities that have this feature rate it “essential” (56 percent), “desirable” (39 percent), or of “minimal value” (6 percent) for situational awareness. Entities that do not have this feature rate it “desirable” (40 percent), of “minimal value” (50 percent), or of “no value” (10 percent) for situational awareness. Table 5.4-3 shows that the majority of the industry has access to automatic paging from a critical applications monitor although other internal methods of notifying support personnel may be employed.

Response	All	RC	Others
Yes	20/40=50%	11/15=73%	9/25=36%
No	20/40=50%	4/15=27%	16/25=64%

Table 5.4-3 — Entities that Can Page Support Personnel When a Critical Real-time Tool is Unavailable or Stalled, as Determined by the Critical Applications Monitor Tool

The data are insufficient to evaluate the usage and implementation of survey respondents’ critical applications monitor tools. Ideally, to ascertain critical real-time tool status, the monitoring tool should be independent of the critical real-time tool being monitored. For example, if the critical applications monitor tool tracks the alarm tools application, the critical applications monitor tool and the alarm tools application should not reside on the same server. Further investigation is needed to determine whether this scheme is in use in the industry.

Recommendations for New Reliability Standards

Because continual monitoring of the availability of critical equipment/critical real-time tools is essential to for reliable power system operation, as supported by the survey results, RTBPTF recommends adding new critical applications monitoring requirements to existing standard IRO-005 (Reliability Coordination – Current Day Operations), to strengthen operator situational awareness.

Critical applications monitoring requirements could, in principle, also be added to NERC’s cyber security standards CIP-002 through CIP-009, which address securing critical cyber assets and requiring that tools and processes be established so that minimum security controls are in place to protect critical equipment. Specifically, Standard CIP-007, Requirement 6 mandates that responsible entities ensure that all cyber assets within the electronic security perimeter, to the degree technically feasible, implement automated tools or organizational process controls to monitor system events related to cyber security. However, Standard CIP-007 does not explicitly address operator awareness of critical applications that may affect the reliable operation of the bulk electric system; rather, it focuses on automated tools or organizational process controls to monitor system events related to cyber security only. Therefore, RTBPTF recommends adding the critical applications monitoring requirements to Standard IRO-005. This standard is a more appropriate location for the requirements because the purpose of IRO-005-1 is to ensure operator awareness of bulk electric system parameters.

RTBPTF Recommendations

The requirements recommended for addition to existing Standard IRO-005 are stated below. The full text of interrelated requirements applicable to critical equipment, which comprises three areas, (change management tools and practices (Section 5.2), facilities monitoring (Section 5.3), and critical applications monitoring) is presented here for clarity. The requirements related to the topic of this section of the report, critical applications monitoring, are highlighted in italic font:

PR1. *Each reliability coordinator and transmission operator shall monitor and maintain awareness of critical equipment status to ensure that the unavailability of critical equipment does not impair the reliable operation of the bulk electric system. Other entities supporting or complementing the reliability coordinator's or transmission operator's ability to operate the bulk electric system reliably shall be subject to the same requirements as the reliability coordinator or transmission operator respectively.*

PR1.1. *Identification of critical equipment — Each reliability coordinator and transmission operator shall identify the critical equipment it uses for bulk electric system operation and monitoring. This includes the critical equipment of parties to whom the reliability coordinator or transmission operator has delegated reliability functions. Each reliability coordinator and transmission operator shall maintain a Critical Equipment Identification Document that lists all critical equipment. The Critical Equipment Identification Document shall be kept current at all times.*

PR1.1.1. *Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical real-time tools used in the operation and monitoring of the bulk electric system: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.*

PR1.1.2. Each reliability coordinator and transmission operator shall include, at a minimum, the following list of critical equipment used in the operation and monitoring of the bulk electric system: servers or computers that contain the critical real-time tools specified above and the data links that provide the input to the critical real-time tools specified above.

PR1.2. *Monitoring of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Monitoring Document identifying its tools and procedures for monitoring critical equipment (which includes critical real-time applications). This document shall describe how to verify that the tools and procedures are functioning and being used as intended. This document shall describe the tools and procedures for operator notification when critical equipment is unavailable.*

PR1.2.1. Each reliability coordinator and transmission operator shall implement automated tools or organizational processes to monitor critical equipment (which includes critical real-time applications) and related system events to ensure reliable operation of the bulk electric system. These tools or organizational processes shall be described in the Critical Equipment Monitoring Document.

PR1.3. Each reliability coordinator and transmission operator shall maintain event logs pertaining to critical equipment (which includes critical real-time applications) status for a period of one year. At a minimum, the event logs shall contain the following information regarding any event that affects the functionality and/or availability of critical equipment. The event log shall address the following questions: What happened? When did it happen? Who was notified? What was the resolution?

PR1.4. Maintenance of Critical Equipment — Each reliability coordinator and transmission operator shall maintain a Critical Equipment Maintenance and Testing Document identifying its tools and procedures for maintenance, modification, and testing of critical equipment. This document shall describe how to verify that the tools and procedures are functioning and being used as intended.

RTBPTF recommends the following measures for the requirements stated above. The measures related to change management tools and practices are written in italic font.

PM 1. *Measures for Critical Equipment Monitoring*

PM 1.1 *The Critical Equipment Identification Document must be available as specified in Requirement PR1.1. Additionally, each* *reliability coordinator and transmission operator shall demonstrate that the Critical Equipment Identification Document is kept current at all times.*

PM1.1.1. *As specified in Requirement PR1.1.1, the Critical Equipment Identification Document must contain, as part of its list of critical real-time applications, the following applications: alarm tools, telemetry data systems (includes applications for SCADA and ICCP Data Link telemetry data), state estimator, network topology processor, and contingency analysis.*

PM1.1.2. As specified in Requirement PR1.1.2, the Critical Equipment Identification Document must contain, as part of its list of critical equipment, the following equipment: servers or computers that contain the critical real-time tools, and the data links that provide the input to the critical real-time tools specified.

PM 1.2 *The Critical Equipment Monitoring Document must be available as specified in PR1.2. Additionally, each reliability coordinator and transmission operator must demonstrate that the Critical Equipment Monitoring Document is kept current at all times and that the documented tools/procedures are used as intended*.

PM1.2.1. Each reliability coordinator and transmission operator must demonstrate, upon request, its capability to monitor critical equipment via automated tools (e.g., critical equipment status displays or visualization tools) or organizational processes (e.g., trouble notification processes) as stated in Requirement PR1.2.1.

PM 1.3 Each reliability coordinator and transmission operator must demonstrate that the event logs as stated in Requirement PR1.3 contain the required information.

PM 1.4 The Critical Equipment Maintenance and Testing Document must be available as specified in PR1.4.

Rationale

The “Purpose” section of Standard IRO-005 states, “The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.” RTBPTF believes that information on critical applications’ status is essential to the RC’s continuous awareness of conditions that may impair its ability to operate the bulk electric system reliably. Lack of awareness that critical real-time tools (e.g., FE’s alarm processor application) were unavailable significantly contributed to lack of operator situational awareness in the August 14, 2003 blackout, as noted in the *Outage Task Force Final Blackout Report.*

If a new requirement is not established for monitoring of critical real-time tools, operators may be unaware when these tools (such alarm tools or contingency analysis applications) are unavailable, which could impair their ability to monitor interconnected bulk electric system reliably.

RTBPTF includes TOPs in the recommendations stated above because these entities are subject to the Reliability Toolbox requirement and are required to have the critical equipment that provide the infrastructure for these tools.[13]

Recommendation – G16

Develop a process for monitoring critical real-time tools including change notification, status update, and severity of a situation.

Recommendations for Operating Guidelines

The survey results show that critical applications monitors are widely used by all types of entities in the industry. Although the survey did not quantify the tool's effectiveness, it is clear that awareness of the availability and status of critical real-time tools increases operators' situational awareness, which is essential for reliability monitoring as required by existing NERC standards. Because of the prevalence of critical applications monitor use, the following recommended operating guidelines appear feasible.

RTBPTF recommends development of the following operating guidelines for the critical applications monitor application. These guidelines support the recommended additions to Standard IRO-005-1 described above.

- Each reliability coordinator should have a demonstrated process for monitoring critical real-time tools. This monitoring process should have the objective/purpose of enhancing operator awareness of the availability of critical real-time tools. The monitoring process should, at a minimum, include the following:
    - Notification of management, operators, and support personnel when critical real-time tool are unavailable
    - Analysis and resolution process for critical real-time tool failures

[13] See the Reliability Toolbox Rationale and Recommendation section as well as the recommendations for each tool in the Reliability Toolbox.

- Critical real-time tool status should, at a minimum, be one of the following: (a) available — running, (b) available — stalled, or (c) unavailable. For example, if the critical real-time tool is functioning correctly (i.e., the output data are updating), the application would be deemed AVAILABLE — RUNNING. If for some reason, the application process/task is still alive but the output data from the application are not updating (because of internal application problems/issues), the application would be deemed AVAILABLE — STALLED. If the application/process is dead or non-existent (e.g., the application failed because of a core dump), the application would be deemed UNAVAILABLE.
    - If possible, the critical applications monitor should specify the severity of the situation, i.e., indicate the action to take to return the tool to AVAILABLE — RUNNING status. "High severity" would mean that a total system reboot is necessary to correct the UNAVAILABLE state.

Recommendation – A17

Investigate whether critical application monitor tools should be independent of the critical real-time tool being monitored.

Areas Requiring Additional Analysis

Ideally, in order to ascertain critical real-time tool status, the critical applications monitor tool should be independent of the critical real-time tool being monitored. For example, if the critical applications monitor tool monitors the alarm tools application, the critical applications monitor tool and the alarm tools application should not reside on the same server. Further investigation is needed to determine the prevalence of the use of this scheme throughout the industry.

Examples of Excellence

RTBPTF cites Tennessee Valley Authority's use of a critical applications monitoring tool that monitors all critical and non-critical processes on their SCADA system as an example of excellence (See EOE-20 in Appendix E).

RTBPTF cites International Transmission Company's use of a critical applications monitoring tool that that monitors the status of their state estimator and ICCP data applications as an example of excellence (See EOE-21 in Appendix E).

RTBPTF cites American Transmission Company's use of overview displays that not only show system performance but also EMS health checks as an example of excellence (See EOE-22 in Appendix E). These overview displays allow the system operator to determine whether the EMS is operational and functioning properly.

RTBPTF cites Central and Southwest's use EMS Facilities Monitoring application with its critical applications monitor as an example of excellence (See EOE-23 in Appendix E).

Section 5.5
Trouble-Reporting Tool

Definition

A trouble-reporting tool allows control center tools/applications users (operators and support personnel) to document problems (e.g., application, system, and display difficulties and malfunctions) and resolutions.

Background

RCs, TOPs, and BAs depend on real-time tools to operate the bulk electric system in a coordinated manner and ensure reliable operations under normal and abnormal conditions, as defined in the NERC standards. A trouble-reporting tool allows users to document problems related to critical real-time tools and may also be used to improve existing support processes.

Support processes help ensure the viability of systems and applications that underpin reliability functions in a control center. These processes allow operators to manage control center infrastructure, which evolves as a result of regular technology changes. Computer system outages and lack of infrastructure stability often result from lack of effective support processes, increasing the risk that critical equipment and real-time tools, used by operators to monitor, assess, or perform the actions necessary to maintain the reliability of the bulk electric system, will not be available. As part of support processes, trouble-reporting tools improve computer operations and help control and keep track of trouble report status (e.g., current computer system issues and their estimated time of repair) that may affect operators' situational awareness.

Summary of Findings

Most respondents (67 percent) to the trouble-reporting tool section of the Real-Time Tools Survey have an operational trouble reporting tool. RCs are most likely to use trouble-reporting tools; 94 percent of RCs responding to the survey have these tools. Table 5.5-1 summarizes the survey results.

Entity Type	Percentage of Entities That Have Operational Trouble Reporting Tools
All	31/46=70%
RC	16/17=94%
Others	15/29=52%

Table 5.5-1 — Entities with Operational Trouble-Reporting Tools

Most respondents that have an operational trouble reporting tool rate it "essential" (61 percent) or "desirable" (35 percent) for situational awareness. A minority of respondents (3 percent) rate their trouble-reporting tool as having "no value." One respondent that rates the tool "essential" states that "the Trouble Reporting Tool is used for having an indication of the usage of the EMS Production Support Resources. Additionally, special application incidents, incident reports, and Software Incident Reports are generated and tracked." "Essential" ratings varied across entity types (see Table 5.5-2) although RCs were most likely (88 percent) to assign this rating.

Entity Type	**How do You Rate the Value of Your Trouble Reporting Tool as a Critical Support Tool to Enhance Reliability Operation and Situational Awareness?**		
	"Essential"	**"Desirable"**	**"No value"**
All	19/31=61%	11/31=35%	1/31=3%
RC	14/16=88%	2/16=13%	0/16=0%
Others	5/15=33%	9/15=60%	1/15=7%

Table 5.5-2 — Value of Trouble Reporting, by Entity Type

The survey results also show that for most entities (93 percent), the trouble-reporting tool is a stand-alone application that is not integrated into EMSs. No tool features emerged as predominant among entity types. The following features were addressed in the survey:

- Display Attachments — This function allows users to attach displays or bitmap images to a trouble report. This feature allows users to efficiently describe a problem by attaching a display or bitmap image of it. (Forty-seven percent indicate that they have this feature, and 27 percent indicate that this feature is "essential" for situational awareness).
- Summary Reports — This function allows users to generate summaries (e.g., trouble reports by functional area) for analysis of trends. (Fifty-nine percent indicate that they have this feature, and 36 percent indicate that it is "essential" for situational awareness).
- Direct User Feedback — This function allows the application to indicate who originates a trouble report and the current status of the report. (Sixty-two percent indicate that they have this feature, and 28 percent indicate that this feature is "essential" for situational awareness).

Recommendations for New Reliability Standards

RTBPTF does not recommend any new reliability standards requiring use of a trouble-reporting tool. RTBPTF believes that the recommendations in Section 5.2, Change Management Tools and Practices, are sufficient to support operator situational awareness related to critical equipment and critical real-time tool maintenance, modification, and testing processes. RTBPTF believes that the trouble-reporting tool is useful and could be integrated with support processes required by the standards recommended in Section 5.2. The trouble-reporting tool could be used formally to document support processes.

Recommendations for Operating Guidelines

The survey results show that trouble-reporting tools are not as prevalent among industry entities as other tools despite the perceived value of trouble-reporting tools for enhancing support processes. The survey results did not quantify the effectiveness of the trouble-reporting tool, but it appears clear that having a tool to track problems and resolutions related to critical equipment and critical real-time tools will enhance situational awareness for both support personnel and operators. However, because change management processes vary in the industry, RTBPTF does not recommend development of new operating guidelines for trouble-reporting tools at this time. Operating guidelines recommended in Section 5.2 are sufficient.

Areas Requiring Additional Analysis

RTBPTF identified no areas requiring additional analysis for trouble-reporting tools.

Examples of Excellence

RTBPTF cites Florida Power and Light's (FPL) Trouble Report System, which facilitates logging, communication, and tracking of user problems with tools and systems maintained by the computer support group at FPL's System Control Center as an example of excellence (See EOE-24 in Appendix E). In addition to allowing entries of new trouble reports, the application performs administrative functions and can produce different query-based summary reports.

Section 6.0
Next Steps

NERC and the industry have much work to do to implement the RTBPTF recommendations described in this report for revised standards and operating guidelines to improve electric system reliability through better real-time operating tools and practices. In addition, NERC and the industry have much to do to conduct the necessary additional analyses of issues for which the task force could not provide specific, technically defensible recommendations or that were outside task force's scope.

To initiate the next steps in the process, RTBPTF proposes to finish work on the specific activities discussed below, which will complete the remainder of the task force's scope of work as assigned by the NERC Operating Committee (OC). Following completion of these activities, RTBPTF will disband.

RTBPTF's recommendations are intended to inform the standards development process. With assistance from NERC staff, RTBPTF will append its recommendations for revised standards to the existing Standards Review Forms that are included in the NERC Standards Development Plan: 2007–2009.[14] The relevant recommendations will be added to the "To Do List" section of the form for each affected standard along with other issues already identified from various sources such as the *FERC Staff assessment* of the NERC standards and comments on the standards from various industry stakeholders. As the standards development plan proceeds, RTBPTF will provide technical support to the standards drafting teams that will author the necessary revisions in accordance with the NERC Reliability Standards Development Procedure.[15]

RTBPTF will also prioritize the areas that the task force identified as requiring more analysis. For areas that the task force believes must be addressed by a new team of experts, RTBPTF will offer to write high-level scopes of work in the form of bullet points that the new teams should consider in drafting their own charters. RTBPTF will deliver the prioritized list of areas needing additional analysis to the NERC ORS and will prepare scope-of-work bullet points as requested by the ORS.

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[14] FERC_Filing_Volumes_I-II-III_Reliability_Standards_Development_Plan_30Nov06.pdf on www.nerc.com
[15] http://www.nerc.com/standards/newstandardsprocess.html

Recommendation – I6

Provide adequate funding and staffing for maintaining and upgrading real-time tools.

RTBPTF also recommends that others take two important additional steps that are outside the scope that the OC assigned to the task force. First, the task force recommends that the OC direct the ORS to determine how operating guidelines are to be developed and maintained. Consistent with the work already done by the ORS in this area, RTBPTF suggests that ORS consider asking the regional reliability organizations (RROs) to develop operating guidelines as "supplements" to NERC standards. Second, the task force urges NERC to develop a plan to address each of the "six major issues" identified by RTBPTF and described in the Introduction to this report.

RTBPTF does not take a position on the disposition of the Examples of Excellence listed in Appendix E of this report. They are presented for consideration by NERC and the industry, with the disclaimers noted in Appendix E.

Glossary of Terms Used in this Report

The following are definitions of terms used throughout this report. The report also contains terms as defined in the "Reliability Standards for the Bulk Electric Systems of North America" document.[1]

Term	Definition
Alarm tools	Applications that emit real-time visible and audible signals to alert operators to events and conditions affecting the state of the bulk electric system. Alarm tools can be external, embedded within the SCADA/EMS system, or a combination of both.
Automatic safety bet	Visualization tool that provides the tools/displays for operators to monitor, initiate, or disable triggering of schemes that shed firm load for under voltage or under frequency conditions. Automatic safety net could work with a remedial action scheme monitor.
Outage Task Force Final Blackout Report	U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April.
Bulk Electric System Elements List	A term developed by RTBPTF to refer to a list of specific bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) within an RC area. The Bulk Electric System Elements List shall contain the necessary bulk electric system elements (within the RC area) so that potential or actual SOL/IROL violations could be identified.
Change management tools	Tools and practices used by support personnel to maintain, modify, and/or test critical equipment that operators use to monitor and perform necessary actions to maintain reliability of the bulk electric system.
Commercial/industrial demand-side management	See "Commercial/industrial load management"
Commercial/industrial load management	Tools that enable operators to curtail commercial/industrial electric demand. This type of tool is similar to residential load or demand-side management but is applied to commercial/industrial customers. A typical application of this type of tool is the disconnection of the electric supply feed from the supplying entity through direct computer control by operators to reduce electric demand.
Congestion management application	Application used for relieving network congestion within an entity's service territory using operational means that lie within the entity's control authority, e.g., generation redispatch, curtailment of transactions within the entity's service area, capacitor bank switching, opening low voltage lines, etc. Typically, it may be a security-constrained dispatch program, an optimal power-flow program, or a heuristic program that searches for the best solution from a set of options. For an ISO or an RTO, this may be part of the LMP application.

[1] For these terms, please refer to the Glossary in the latest official copy of the NERC Reliability Standards, which can be found at http://www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html.

Term	Definition
Contingency analysis	Computer application used to analyze the impact of specific, simulated outages (lines, generators, or other equipment) or higher load, flow, or generation levels on the security of the system. Contingency analysis identifies problems such as line overloads or voltage violations that will occur if a new event (contingency) happens on the system. The state estimator solution is a representation of current system conditions and usually serves as the base case in the analysis. The information a contingency analysis generates enables RCs and TOPs to implement mitigation plans in advance of a contingent event such as a line trip. Contingency analysis is used as a real-time application as well as for studying potential scenarios.
Critical applications monitoring	Tracks the status of critical real-time tools. This application allows operators and/or support group personnel to track availability of critical real-time tools. Critical real-time tools must be available for operators to monitor, assess, and perform the necessary actions to maintain the reliability of interconnected bulk electric systems. A critical applications monitor tool may be part of a facilities monitor tool.
Critical equipment	Installed equipment that makes up the infrastructure and systems (including communication networks, data links, hardware, application software, and databases) that are directly used as the computer infrastructure for critical real-time tools. Critical equipment is essential for all reliability entities to ensure the reliable operation of the bulk electric system. Critical equipment is a subset of critical cyber assets.
Critical facility loading assessment	Application that evaluates a set of contingencies and calculates the post-contingency loading of a set of monitored facilities using telemetered SCADA flows and LODFs. CFLA may be used as a backup application if the state estimator and/or contingency analysis applications fail.
Critical real-time tool	Installed software that is essential to support, operate, or otherwise interact with bulk electric system operations. Critical real-time tools do not include process control applications, distributed control system applications installed in generating stations, switching stations, or substations.
Display maintenance tool	Tool used by support personnel to develop and maintain visual interfaces that operators use to maintain situational awareness, i.e., to monitor and assess bulk electric system reliability and/or take action to maintain system reliability.
Dynamic mapboard	Physical collection of painted lines, status lights, and analog readouts presenting, in a stationary prominent location, continuous real-time status of important selected components of the power system to operators. It is “dynamic” because the statuses of important selected components of the power system are updated in real time. A dynamic mapboard usually complements common SCADA/EMS displays.

Term	Definition
Dynamic overview display	One-line and other graphical displays depicting the state, loading, and/or voltage levels over the wider area (or a sub-area within the entity's internal footprint) of the power system. Dynamic overview displays are essentially large SCADA one-line displays. Examples of this type of visualization tool are area overview one-line displays, which are one-line displays that show a group of electrically connected substations for a specified area.
Dynamic stability assessment	Application (or a suite of applications) executing in near-real time that aid in determination of system operating limits based on transient dynamic stability assessment using a current state estimator model of the real-time system. A dynamic stability assessment may also provide an indication of the dynamic stability margin for the most critical fault/contingency condition.
Emergency tools	Applications or procedures that operators use when the power system enters or is about to enter an emergency. The NERC Glossary defines "emergency" as "[a]ny abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System."
Facilities monitor	Tracks the status of computer systems equipment, servers, backup systems, communications systems, networks and other critical facilities. This tool allows operators and/or support personnel to be aware of critical equipment issues that may affect the availability of critical real-time tools used to operate and monitor the bulk electric system.
Flowgate monitor	Visualization tool that provides the tools/displays for operators to monitor actual and contingency flows on designated flowgates. The NERC Glossary defines "flowgate" as "[a] designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions." This type of visualization tool provides flowgate information to operators; it could run either within or independent of SCADA/EMS systems.
Inter-control center communications protocol	Inter-Control Center Communications Protocol (ICCP) is a standard data exchange protocol that is widely used in the electric utility industry to communicate information between operating entities. The NERC ISN utilizes ICCP to support data exchange among RCs, and several intra-regional and intra-company networks also use this protocol to support the provision of data to RCs from operating entities within the RC area.
Inter-regional real-time coordination for market redispatch	Application used to adjust the market dispatch within the entity's service territory in coordination with adjacent RCs to manage the inter-regional congestion problem in real-time. This tool may be handled by the entity's congestion management application, or it may be handled through a different process.

Term	Definition
Inter-regional voltage profile coordination	Application that coordinates the voltage profiles between two or more regions. This application may contain features such as wide-area voltage contour visualization, voltage schedule coordination between regions, etc.
Line outage distribution factor	Estimation of impact from an outage over a facility can be done using LODF. In general, an outage impacts the system by transferring the amount of power flowing on the outaged elements during pre-contingency conditions to other facilities in the system. These changes could increase or decrease power flow on the facilities depending on network topology, load, and generation dispatch. LODF is formulated as a percentage of pre-contingency flow on the outaged line that appears on the monitoring facility during contingency conditions.[2]
Load reduction by voltage reduction	Enables the operator to curtail electricity demand by reducing the distribution-level voltages. This scheme usually involves direct computer control (via SCADA systems) to automatic voltage regulating relays on LTC power transformers and step voltage regulators. By means of the control of the dry contact closure to the regulating relay, its regulating center band voltage is reduced to a lower level by boosting the sensed voltage of the voltage regulating relay. This causes a reduction of the distribution voltage schedule, which reduces electricity demand for a short period.
Locational marginal pricing	A market-pricing approach used to manage the efficient use of the transmission system when congestion occurs on the interconnected bulk electric system.
Network topology processor	SCADA-based application that determines facility status and station configuration based on breaker and switch status data. The processor converts a nodal network model into a bus-branch model, for use by other applications such as the state estimator. It may perform the same function for study network applications such as power flow.
Offline power flow	See "Power Flow"
Online power flow	See "Power Flow"
Operator	System operator
Power flow	Application used to calculate the state of the power system (flows, voltages, and angles) by using available input data for load, generation, net interchange, and facility status. Power flow is divided into two categories: "online power flow" and "offline power flow." An "online power flow" application is typically integrated within an EMS (or has a direct data feed from an EMS) and utilizes node-breaker topology whereas "offline power flow" is based on bus-branch models and static data. Power flow is widely used in real-time systems to assess system conditions or perform look-ahead analysis. Power flow is also used to study "n-1" contingencies and to identify potential future voltage collapse or reliability problems.

[2] Source: http://www.caiso.com/docs/2005/05/03/200505031714217356.pdf.

Term	Definition
Reactive reserve monitor	Visualization tool that allows operators to monitor reactive reserves (from static and dynamic sources) in local geographic areas or major load centers. This visualization tool can alarm the operator when a generating unit has reached its reactive capability or an area has approached the minimum reactive reserve requirement. This type of visualization tool could also be the real-time user interface representation of the documented set of procedures, practices, or guidelines for maintaining awareness of the current and near-term reactive reserve capability.
Real-Time Tools Best Practices Task Force	The task force responsible for this report
Real-time contingency analysis	See "contingency analysis"
Remedial action scheme monitor	Visualization tool that provides the tools/displays for operators to monitor the status of critical power system parameters and measure the proximity of these parameters to the triggering conditions for special protection schemes or total system failure. This tool alarms and advises operators of actions required to mitigate the pending power system condition.
Residential demand-side management	See "residential load management"
Residential load management	Enables the operator to curtail residential electric demand for specific appliances. Residential load or demand-side management (DSM) consists of planning, implementing, and monitoring activities designed to encourage residential consumers to modify their level and pattern of electricity usage. These activities are also designed to shape electricity demand through direct computer control of specific appliances. For example, when necessary, operators could turn off air conditioners of residential customers that sign up for a residential DSM program.
Rotating load shed	Enables the operator to curtail load by initiating or scheduling load shedding. The *Outage Task Force Final Blackout Report* defines "load shedding" as "… the process of deliberately removing (either manually or automatically) pre-selected customer demand from a power system in response to an abnormal condition, to maintain the integrity of the system and minimize overall customer outages." For this type of tool, rotating load shed refers only to manual load shedding scheduled or initiated by operators via computer control.
SCADA one-line display	Dynamic, one-line diagram displays of substations and major power system components that present the real-time status and selected flow, voltage, and other data of the power system. This is the most common type of visualization tool used today to monitor bulk electric system elements or parameters.
Security-constrained dispatch	See "congestion management application"
Selectable data trending	Visualization tool that provides the ability to plot graphically selected power system values, using up-to-date data on the plot at a reasonable refresh rate on real-time displays used by operators and others. Displays are used by system operators and others.

Term	Definition
Short-term load forecasting	Application that predicts short-term (next 0-60 minutes) loads based on parameters such as short-term weather effects, current load, etc. The result from this tool could be used for predictive redispatch, look-ahead contingency analysis, awareness of scheduled non-conforming load changes, etc.
Short-term weather forecasting	Application that predicts short-term (next 0-60 minutes) extreme weather that may impact operations, e.g., a lightning prediction tool, Doppler radar, etc.
Short-term wind energy forecasting	Near real-time application that is used to predict and manage generation in response to the variability of supply from wind-energy sources.
Short-term hydro scheduling	Real-time application used to manage deviations from the long-term optimized schedule (for hydro units) for reasons of reliability, e.g., a response to a DCS event, acquiring support for localized voltage control, etc.
State estimator	Application that performs statistical analysis using a set of imperfect, redundant, telemetered power system data to determine the system's current condition. The system condition or state is a function of several variables: bus voltages, relative phase angles, and tap changing transformer positions. A state estimator can typically identify bad analog telemetry, estimate non-telemetered flows and voltages, and determine actual voltage and thermal violations in observable areas. The state estimator application has two main uses. It provides (1) a base case for reliability-analysis applications, and (2) input to other system monitoring tools. The state estimator solution is typically used as the base case for other reliability-related applications, such as contingency analysis. In some cases, the state estimator is used primarily as the basis for information communicated to operators regarding power system status, e.g., the state estimator drives the alarm application that alerts operators to power system events.
State estimator one-line display	Dynamic, one-line diagram displays of substations and major system components that present the state estimator solution for status and selected flow, voltage, and other data from the power system.
Study area one-line display	Study area one-line displays are one-line diagram displays of substations and major system components that present the active study context of status and selected flow, voltage, and other data from the power system model in use. Examples of this type of visualization tool are power flow one-line displays, contingency analysis one-line displays (for a specified contingency), etc.
Study real-time maintenance	Application that simulates real-time network applications (e.g., NTP, state estimator, contingency analysis, etc.) and debugs problems without affecting the operation of the real-time applications. Can be an on-line application integrated with the production EMS system, an application integrated with a non-production EMS system (i.e., DTS, etc.), or an off-line application.

Term	Definition
Telemetry data	Status and analog values originating from conventional SCADA/EMS or equivalent systems (telemetry data systems) and are updated continuously in real-time or near-real-time operation. These data may come directly from SCADA system(s) or from direct connection (ICCP, ISN, etc.) to SCADA systems operated by others.
Telemetry data systems	Tools or applications that process and provide telemetry data. SCADA is an example of a telemetry data system.
Topology and analog error detection	Application that identifies and/or automatically overrides incorrect SCADA breaker and switch statuses to enhance a NTP and to improve the accuracy and robustness of the state estimator. May also identify and/or automatically ignore SCADA analog measurements that are unreasonable or inconsistent with network connectivity.
Transaction impact monitor	Type of visualization tool that provides the tools/displays for operators to monitor scheduled transactions and interchange flows between balancing authorities.
Trouble-reporting tool	Allows control center tools/applications users (operators and support personnel) to document problems (e.g., application, system, and display difficulties and malfunctions) and resolutions.
Visualization tools/techniques	A group of user interface applications, tools, or displays that provide concise visual monitoring and enhanced multiple views of relevant power system data in real time to operators and others. Visualization tools help operators monitor and better understand system events and/or conditions across neighboring power systems that may be affecting reliable operations in their part of the power system.
Voltage stability analysis	Application executing in near-real time that aids in determination of system operating limits based on voltage stability assessment using a current state estimator model of the real-time system. VSA may derive minimum voltages at key buses below which voltage collapse may occur under further stress to the system, evaluate whether sufficient stability margins exist for an analyzed base case, provide margins relative to particular stress modes such as transfers or system loading, or provide information on minimum dynamic reactive reserves required in local areas.
Wide-area view boundary	The NERC glossary defines “wide area” as “[t]he entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.” RTBPTF defines “wide-area view boundary” as the network model boundary for the “wide area.” For reliability coordinators, the “wide-area view boundary” defines the minimum required network model in order to support the monitoring requirements for the “wide area.” This network model should contain all the bulk electric system elements (generators, transmission lines, buses, transformers, breakers, etc.) bounded by the wide area view boundary.

Term	Definition
Wide-area visualization tools	Displays/tools driven by SCADA, EMS, PMU, disturbance recorder, and other technical data collected in real time that present concise information for the “wide area.” In general, these displays/tools show multiple views of the status of critical facilities within the entity’s internal footprint, but they are also used to show views of critical facilities or data from the entity’s external footprint that have the potential for adverse impact to the internal system (the “wide area” as defined in the NERC Glossary). By this definition, dynamic overview displays may also be considered wide-area visualization tools. Besides the traditional SCADA/EMS displays that show critical reliability parameters, wide-area visualization tools use other forms of technology/methodology to present vast amounts of information in a form such that the operator can assess the state of the system in an intuitive and quick manner.

Appendix A
Real-Time Tools Survey Development and Software

Introduction

RTBPTF's scope includes the assignment to "develop a focused survey (preferably web-based) for distribution to entities responsible for reliable operations to determine which tools those entities use to perform state estimation, perform real-time contingency analysis, and maintain situational awareness of their systems." To fulfill this assignment, the task force developed the Real-Time Tools Survey and delivered it as an interactive, on-line, web-based questionnaire. Lawrence Berkeley National Laboratory provided programming, database, and systems integration services for the survey. This Appendix summarizes the survey's development and briefly describes the software system that was created to support it, including its testing, quality assurance, and role in the survey analysis.

Summary of Survey Development

The survey in its final form was more than 300 pages long, with nearly 2,000 questions organized into five major sections: Real-Time Reliability Tools, Situational Awareness Practices, Real-Time Data Acquisition and Exchange, Modeling Practices, and Support and Maintenance Practices related to the real-time tools.

Real-Time Tools

The initial basis for the selection of the real-time tools investigated in the survey was a report on minimum requirements and best practices for reliability software, presented at a July, 2004 FERC technical conference on Information Technology for Reliability and Markets, (Docket No. PL04-12-000).[1] Starting from the applications addressed in that presentation, RTBPTF narrowed the list to real-time operator tools. (The task force did not consider long-term, medium-term, day-ahead, training, or market or economic operations tools.) Based on their collective expertise and experience, the task force members then developed a complete list of reliability tools that directly support situational awareness and formulated definitions for each tool. Special emphasis was placed on tools to aid operator situational awareness because the *Outage Task Force Final Blackout Report* repeatedly points to lack of operator situational awareness as a key cause of the August 14, 2003 blackout. The real-time tools portion of the survey was designed to elicit, from different types of entities responsible for reliable

[1] Macedo, Frank. Consultant to FERC. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14.
http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps

operation of the bulk electric system, descriptions of their use of each tool. The task force's goal was to characterize, based on the survey results, each tool's industry-wide status.

Situational Awareness Practices

The task force reviewed the then-current NERC reliability standards to identify elements of situational awareness that were addressed to some extent in the standards. These elements formed the basis for survey questions on operating practices, processes, and procedures used to maintain situational awareness.

Data, Modeling, and Support and Maintenance Tools

The three remaining sections of the survey address the acquisition and exchange of real-time data needed to support real-time reliability tools and practices, the characteristics of the real-time models needed to support those tools (as well as the practices used to build and maintain the models), and other tools and practices to support and maintain real-time reliability tools. These topics were included in the survey because real-time reliability tools require accurate input data, well-designed models, and effective maintenance to produce meaningful results that operators can depend on for situational awareness.

Survey Structure

Task force members extensively debated the optimal structure for the individual questions in the survey. Some members felt that asking general questions that required a detailed, free-format written response would elicit the most comprehensive and insightful information and thus the best basis for identifying candidates for follow-up questioning. The downside to this structure would have been the enormous challenge of analyzing the responses, especially for a questionnaire of this length.

Some task force members favored an alternative structure with sets of specific questions on a particular subject, each having yes/no or multiple-choice answers, designed to elicit, in the aggregate, a complete picture of a topic but requiring minimal effort from respondents. The upside of this approach is that the responses could be easily queried, sorted, and analyzed statistically. The downside is that respondents could not elaborate on their answers.

The final decision was to use a yes/no, multiple-choice structure but to give respondents the ability to add free-format written comments on key topics addressed in the questions.

Each section of the survey described above was broken into individual subsections that addressed specific tools or practices. Within each subsection, the questions were designed and arranged to: identify the types of entities using the tool or practice; inventory the functions of the tool or practice; and rate the value of the tool, function, or practice for situational awareness. In addition, survey respondents were asked to identify what they perceive as *best practices* in their control centers for the particular tool or practice.

The task force finished designing the survey in April 2005 and sent it to Lawrence Berkeley National Laboratory for programming. Beta testing began in June 2005, and the survey was rolled out to reliability coordinators (RCs), transmission operators (TOPs), and balancing authorities (BAs) in August 2005. The task force closed the survey in November 2005 and began analyzing the results in preparation for this final report. The task force presented an overview of its preliminary findings and recommendations to the NERC Operating Reliability Subcommittee (ORS) in November 2006.

Survey Hardware and Software

The RTBPTF on-line survey has two internal components: a web server, and a database, as illustrated in Figure A-1. A secure web server, maintained by NERC staff in Princeton NJ, hosted the survey software. The database stored the questionnaire structure and all of the users' responses. The software generated the web pages through which respondents navigated to read the questions and insert answers by reading directly from the design data (e.g., section, question number, question text, question type) stored in the questionnaire portion of the database. Figure A-2 shows examples of the user interface web pages. All communication between users and the questionnaire took place over an encrypted channel to ensure the security of users' responses. The software used to produce the web site and control the database is written in PHP (www.php.net), which interacts with a MySQL (www.mysql.com) database.

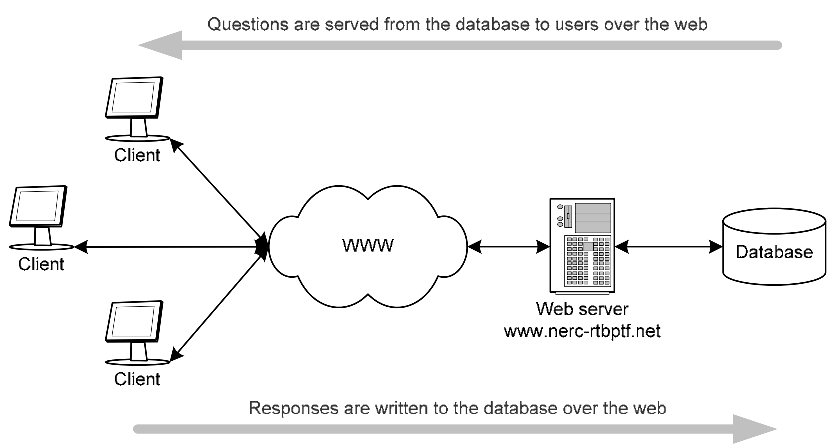

Figure A-1 — Software Communication

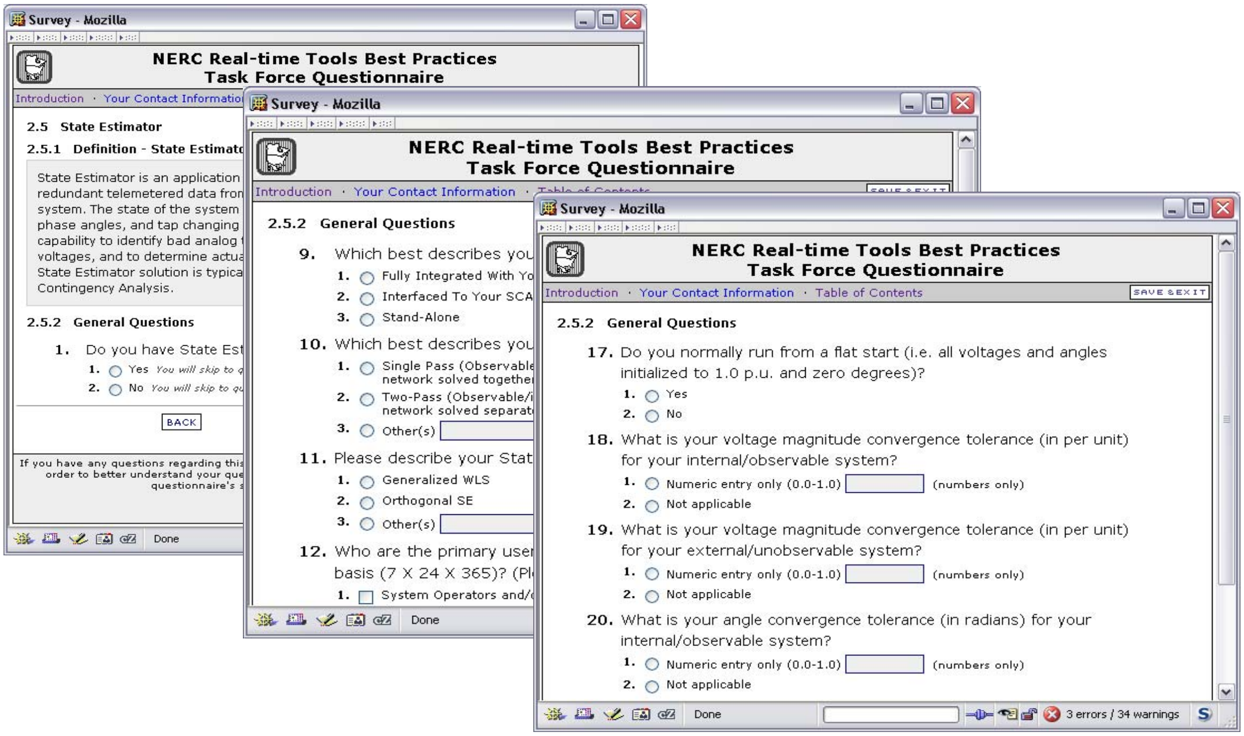

Figure A-2 — User Interface Web Page Examples

Testing

To ensure ease of use and confirm the accuracy of the software application, task force members tested it rigorously prior to release for both completeness and functionality (e.g., navigation among and within survey sections). Improvements in questionnaire content entailed adding or editing database records to add or edit questions. Improvements in questionnaire functionality (e.g., to aid navigation by respondents) entailed direct modifications to the interface software.

Quality Assurance

After the survey period ended, additional software tools were developed that were tailored to task force needs, to interrogate the database and assess consistency among and completeness of user responses. In a few cases, individual users were contacted to clarify conflicting responses.

Interfaces were built on the web server with the following functionalities:

- View survey completion counts by reliability region,
- Download aggregate results of all answers in spreadsheet format,
- View user profiles and download their surveys by reliability region, and
- View aggregate responses for individual questions.

Results/Deliverables

Final output from the questionnaire database was provided in two formats: 1) a report of aggregate responses for each survey question (which can be downloaded as pdfs at: http://www.nerc.com/~filez/rtbptf.html), and 2) the entire questionnaire database in Microsoft Access format.

The report of aggregate responses summarize all responses for each survey question. Responses are presented first aggregated for all respondents, followed by an aggregation of responses received from reliability coordinators.

To mask individual respondents' identities, all comments entered in free-format text fields were globally post-processed to remove references to a specific entity name. These references were replaced with a generic label or term, depending on the context.

The Microsoft Access database containing the raw survey responses is an abridged version of the master MySQL database. Data in the MySQL database specific to the functioning of the web site were not ported to the abridged version. Only data specific to the questions, answers, and respondents were included. The members of the task force received the abridged version to support their individual interrogation and analysis of the questionnaire responses. Figure A-3 shows the database schema.

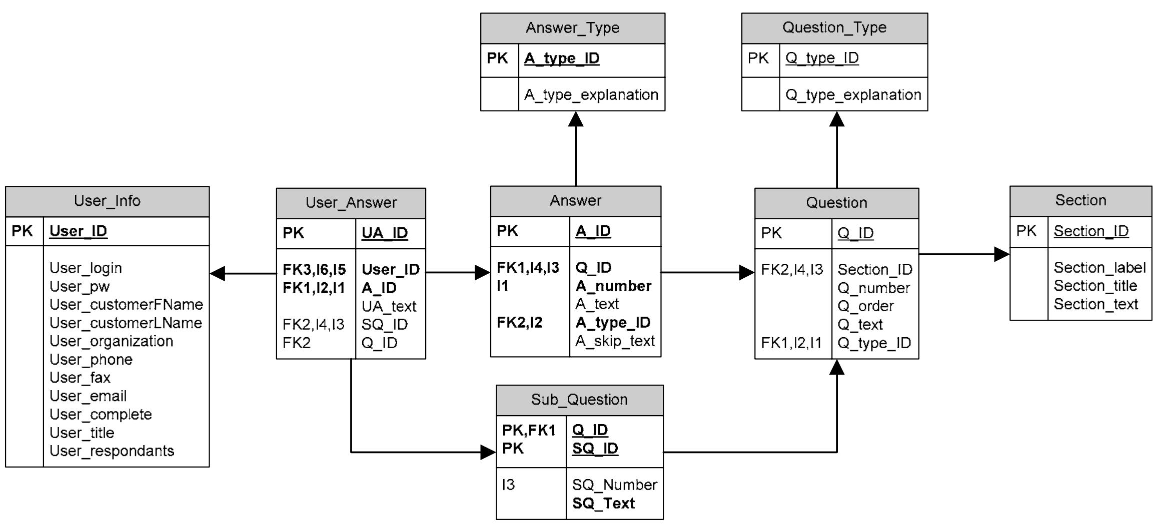

Figure A-3 — RTBPTF Questionnaire Database Schema

Appendix B
Survey Participation

The Real-Time Tools Survey was designed to collect information from NERC registered RCs, TOPs, BAs, and other interested (but unregistered) operating entities who use real-time tools to monitor or analyze the reliability of the bulk electric system. RTBPTF invited representatives from each entity listed in the NERC Transmission System Information Network (TSIN) database to participate in the survey. A total of 59 entities (registered and unregistered) requested access to the survey and completed at least one section. Entities that did not complete at least one section were excluded from the analysis. The survey participants included all 17 North American RCs, 39 TOPs, and 3 BAs (who are not also TOPs or RCs).

Several entities that completed the survey perform more than one NERC function. For example, some entities may serve as both a TOP and a BA; others [e.g., the Electric Reliability Council of Texas] may even serve as RC, TOP, <u>and</u> BA. RTBPTF contacted these "multi-function" entities to clarify their status, and each was reclassified, for purposes of the survey, according to its highest-level function. RCs are considered the highest-level entities, and balancing authorities are considered the lowest-level entities, with TOPs in the middle. Thus, for example, an entity registered as a TOP and an RC would be classified as an RC for the survey analysis; an entity registered as a BA and a TOP would be classified as a TOP. This classification protocol was used to ensure that the information submitted by each participant was not counted more than once in the final analysis of survey results.

Some entities' situations posed classification challenges. One RC contracts some or all of its real-time reliability tools through a registered TOP. The survey response submitted by the TOP for this entity included the RC's response. Therefore, after contacting both entities, the task force reclassified the TOP's response as an RC response. One entity that responded to the survey was not a NERC registered RC, TOP, or BA. After the task force contacted this entity, its response was classified in the category that most closely corresponded to its role.

The entities that participated in the survey are listed below according to the function assigned to each for survey analysis purposes. Figure B-1 shows a map of the geographical footprint of RCs that participated in the survey, and Table B-1 lists the RCs. Figure B-2 shows the footprint of the TOPs and BAs that participated in the survey, and Tables B-2 and B-3, respectively, list the TOPs and BAs.

Reliability Coordinators	
1	Bonneville Power Administration (BPAT) for Pacific Northwest Security Coordinator
2	Southern Company Services, Inc. (SOCO) for Southern Subregion
3	Entergy Services, Inc. (EES)
4	Energy Reliability Council of Texas Independent System Operator (ERCOT)
5	Florida Reliability Coordinating Council (FPL / FRCC)
6	Hydro-Quebec TransEnergie (HQT)
7	The Independent Electricity System Operator (IMO)
8	Independent System Operator New England (ISNE)
9	New Brunswick System Operator (NBSO)
10	New York Independent System Operator (NYIS)
11	Pennsylvania-New Jersey-Maryland Interconnection (PJM)
12	Duke Energy Corporation (DUK) for VACAR-South
13	California Mexico Reliability Coordinator (CMRC)
14	Midwest Independent System Operator (MISO)
15	Rocky Mountain - Desert Southwest Reliability Coordinator (RDRC)
16	Southwest Power Pool (SWPP)
17	Tennessee Valley Authority (TVA)

Table B-1 — Entities who participated in the Real-time Tools Survey and were classified as RCs

	Transmission Operators
1	Alabama Electric Cooperative, Inc. (AEC)
2	Alberta Electric System Operator (AESO)
3	American Electric Power (AEP) - Central & Southwest (CSWS)
4	Associated Electric Cooperative, Inc. (AECI)
5	Cinergy Corp (CG&E)
6	Cinergy Corp (PSI)
7	Cleco Corporation (CLEC)
8	COMISION FEDERAL DE ELECTRICIDAD (CFE)
9	First Energy (FE)
10	Idaho Power Company
11	International Transmission Company (ITC)
12	Lincoln Electric System (LES)
13	Northern Indiana Public Service Co. (NIPS)
14	NorthWestern Energy (NWMT)
15	Oklahoma Gas & Electric (OKGE)
16	Otter Tail Power Company (OTP)
17	Public Service Company of New Mexico (PNM)
18	Grant County Public Utility District (GCPD)
19	Public Utilities District # 1 of Douglas County (DOPD)
20	Santee Cooper (SC)
21	Saskatchewan (SPC)
22	Sierra Pacific Power Company (SPPC)
23	South Carolina Electric & Gas Company (SCEG)
24	Southern Minnesota Municipal Power Agency (SMP)
25	Southwestern Public Service - Xcel (SPS)
26	Tennessee Valley Authority (TVA)
27	Vectren Energy Delivery of Indiana (VEDI)
28	Westar (WR)
29	Western Area Power Administration - Upper Great Plains Region (WAUW)
30	Allegheny Power (AP)
31	American Electric Power (AEP)
32	American Transmission (ATC)
33	Aquila Inc. (WPEL)
34	City Utilities, Springfield MO (SPRM)
35	Dominion Virginia Power
36	HydroOne
37	Lansing Board of Water & Light
38	National Grid – NY / Niagara Mohawk Power Corporation (NMPC)
39	Rochester Public Utilities (RPU)

Table B-2 — Entities who participated in the Real-Time Tools Survey and were classified as TOPs

Balancing Authorities	
1	City of Tallahassee (TAL)
2	Madison Gas and Electric Company (MGE)
3	We Energies / Wisconsin Energy Corporation (WEC)

Table B-3 — Entities who participated in the Real-Time Tools Survey and were classified as BAs

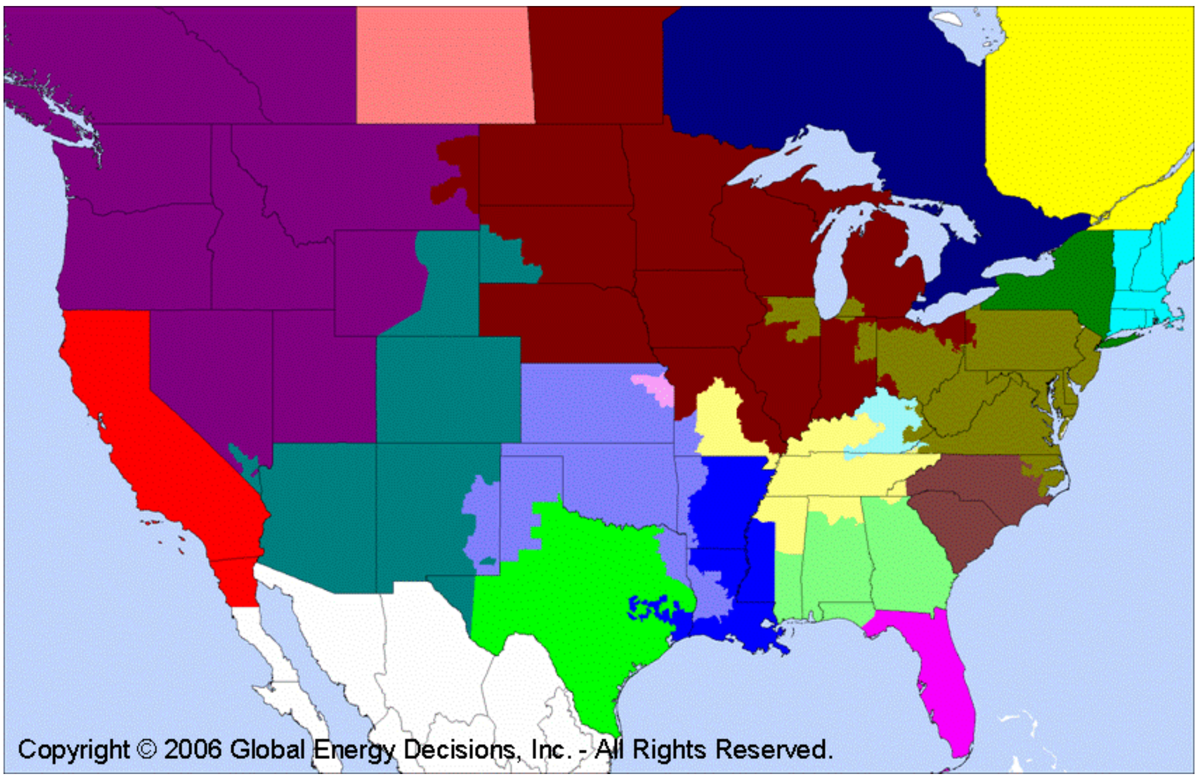

Figure B-1 — Footprint of RCs that participated in the Real-Time Tools Survey

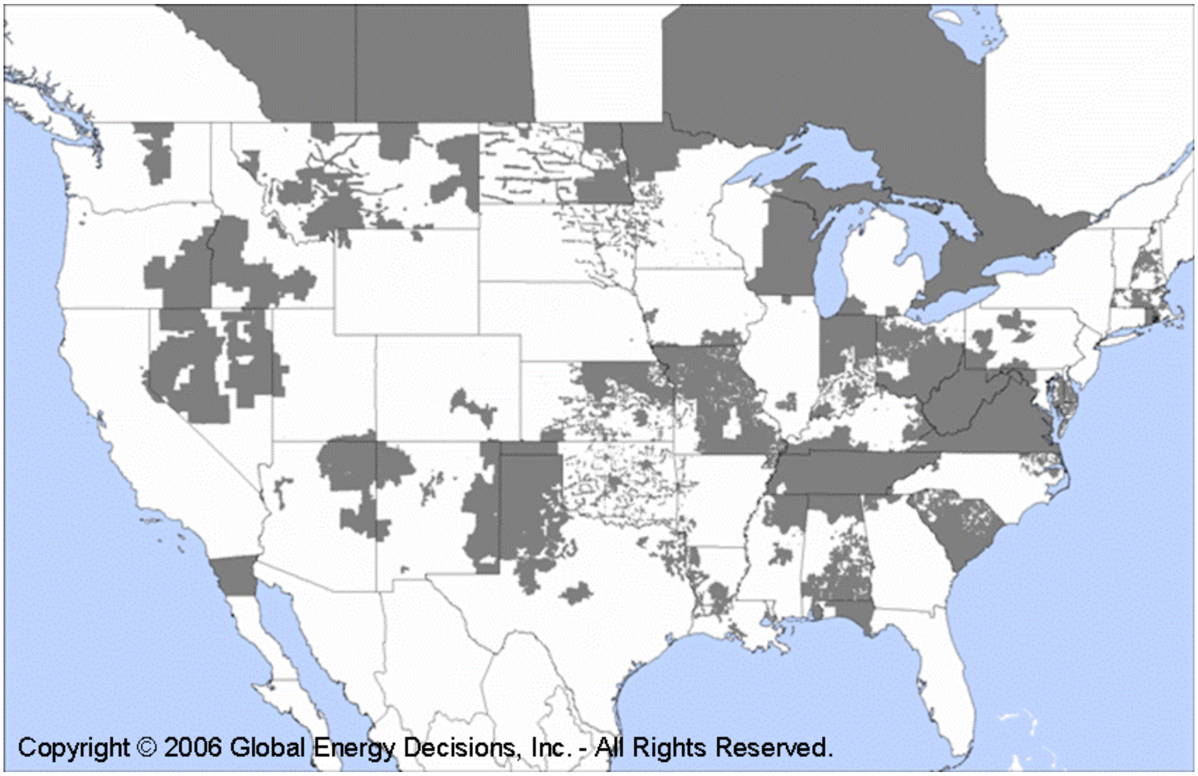

Figure B-2 — Footprint of TOPs and BAs (that are not also RCs) that participated in the Real-Time Tools Survey

Appendix C
Survey Analysis Methodology

Introduction

Given the breadth and depth of the Real-Time Tools Survey, RTBPTF recognized that reviewing and analyzing the survey responses would be a monumental task. This appendix explains the methodology that the task force developed to summarize and analyze the survey results and to develop recommendations from them.

Individual task force members reviewed and analyzed specific survey sections and prepared the corresponding portions of this report. To process the massive number of data from the survey, the task force used summary reports and database query tools. To ensure consistency and uniformity of individual reviewers' efforts and to produce this final, comprehensive report, the task force created and followed a structured methodology and a checklist of key steps.

The sections below describe the tools; checklist; and underlying criteria, principles, and guidelines that the task force used in analyzing the survey data.

Analysis Tools

RTBPTF members accessed the database of all survey responses on a secure web site hosted by NERC. Lawrence Berkeley National Laboratory (LBNL), which created the survey software, also created summary reports of responses organized by survey section. These reports were posted on the secure web site, so task force members could download them. In addition, LBNL created an on-line tool that enabled task force members to query the responses to any individual question and see a breakdown by respondent type – RC, TOP, and/or BA.

Task force members could also download the entire survey database and create their own custom queries and reports. One task force member created a summary report of the entire database in a text format and shared it with the other members. Other members created and shared database queries, indices, spreadsheets, and tables.

Survey Review Checklist

The task force created a checklist that outlined the "roadmap" for the complex journey from raw survey responses to the material needed to prepare a final report that would fulfill the task force's deliverables requirement. The checklist contained the following steps:

- Download and review the results file for each task force member's assigned section

- Use Question Query Tool to review responses to particular questions by entity type
- Download survey database into Microsoft Access and design custom queries as needed
- Prepare initial, high-level lists of findings
- Identify related questions from other sections to validate/invalidate initial findings
- Review initial findings in relation to the report on minimum requirements and best practices for reliability software presented at 2004 FERC technical conference on Information Technology for Reliability and Markets[2]
- Refine and summarize initial findings
- Develop recommendations for new standards based on summary of findings
- Develop recommendations for operating guidelines based on summary of findings
- Identify areas requiring more analysis based on summary of findings
- Identify examples of excellence based on survey responses and follow-up interviews

Principles for Summarizing Findings

To ensure that they did not stray from RTBPTF's scope, the task force members focused, when summarizing the survey findings, primarily on issues directly related to reliability and situational awareness. Thus, they undertook to address causes of the August 14, 2003 blackout that were related to real-time tools and situational awareness, as identified in the NERC Steering Group Report to BOT[3] and the *Outage Task Force Final Blackout Report*.[4] In addition, RTBPTF members reviewed existing reliability standards to identify the ones containing requirements related to the tools or practices covered in the survey and to determine which standards needed new or revised requirements. After FERC

[2] Macedo, Frank. Consultant to FERC. 2004. *Reliability Software Minimum Requirements & Best Practices*. FERC Technical Conference, July 14.
http://www.ferc.gov/EventCalendar/Files/20040716092511-20040714085315-FrankMacedo.pps
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[3] NERC Steering Group. 2004. *Technical Analysis of the August 14, 2003, Blackout: What Happened, Why, and What Did We Learn?* Report to the NERC Board of Trustees. July 13.

[4] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April.

issued its *Staff Assessment* of NERC's proposed reliability standards,[5] RTBPTF endeavored to address the issues raised in the assessment that were germane to the task force's scope.

In summarizing survey findings, the task force differentiated between the responses of RCs and those of other survey participants where possible and relevant. One reason for breaking out RC responses was to highlight any major differences between the reliability tool use and operating practices of RCs and those of other entities. Another reason was that all 17 RCs responded to the survey, so, in statistical terms, the total population of RCs was represented. However, only about one-third of registered TOPs and BAs (who are not also RCs) participated, so those responses represent non-random samples of the populations of TOPs and BAs.

RTBPTF looked for clear majorities in the responses to questions about tool usage and practices to identify prevalent practices, which help form the rationale for many of the recommendations in this report. The tables and statistics in the technical sections of this report are designed to illustrate how many respondents answered specific questions in particular ways. In writing their analyses, task force members attempted to summarize the conclusion supported by each set of statistics and tables.

Other guiding principles for summarizing survey results included: 1) quoting survey respondents' comments when quotes are appropriate and help make a point, 2) not self-censoring findings and recommendations because of anticipated controversies, 3) identifying areas in which most respondents seem to be doing well, 4) identifying areas where the industry in general needs improvement, and 5) identifying important issues where the data are insufficient to properly evaluate a tool or practice or are too inconclusive to justify action.

Criteria for RTBPTF Recommendations

RTBPTF's recommendations in this report are based upon several criteria that the task force established to determine which of the following four options were justified by the survey findings for each topic: 1) recommendation for new reliability standards (or revisions to existing standards), 2) recommendation for operating guidelines, 3) identification of areas requiring more analysis, or 4) identification of examples of excellence. These four options were derived from the task force's understanding of its assigned responsibilities as explained in the discussion of "best practices" in the Introduction to this report. The specific criteria for each option are described below.

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[5] Federal Energy Regulatory Commission (FERC). 2006. *Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards*. www.ferc.gov/indus-act/reliability/standards.asp.

Basis for Recommending New or Revised Reliability Standards

1. Recommendations for revisions to existing standards must support or provide clarification to the existing standards.
2. Recommendations for new reliability standards must pertain to tools or practices that materially affect bulk electric system reliability.
3. Recommended requirements must be measurable.
4. All recommendations must support the NERC Reliability and Market Interface Principles.[6]
5. Recommendations must be made by consensus of RTBPTF's active members.
6. Recommendations should support the needs and gaps identified by the NERC and Outage Task Force *Blackout Reports* and the FERC *Staff Assessment* of NERC standards.

Basis for Recommending Operating Guidelines

RTBPTF's criteria for recommending operating guidelines are based to some extent on the criteria for establishing "Best Practices" identified by the NERC Operating Committee's Best Practices Task Force in its report,[7] which was approved by the NERC Operating Committee in December 2005. A key recommendation of the Best Practices Task Force was that "Operating Guidelines" and "Examples of Excellence" should be established in lieu of "Best Practices." RTBPTF's criteria for recommending practices to be documented as operating guidelines are as follows:

1. Practice must be prevalent within the industry (employed by >50 percent of survey respondents).
2. Practice must support an existing or proposed standard.
3. Practice must be proven to be effective.
4. Practice cannot be considered to be essential to maintaining bulk electric system reliability (because operating guidelines are not mandatory).
5. Practice must be feasible to implement.
6. Practice must be applicable over a wide range of organizations that perform the practice for which the operating guideline applies.

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[6] ftp://ftp.nerc.com/pub/sys/all_updl/tsc/stf/ReliabilityandMarketInterfacePrinciples.pdf

[7] *Best Practices Task Force Report: Discussions, Conclusions, and Recommendations*. 2005. December 1.

Basis for Identifying Areas Requiring More Analysis

1. Were the survey results inconclusive?
2. Was the tool or practice not adequately addressed in the survey?
3. Is the topic a significant “hole” in the overall reliability “fabric?”

Basis for Identifying an Example of Excellence

Because the Real-Time Tools Survey was completed prior to the Best Practices Task Force final report mentioned above, which recommended that "Operating Guidelines" and “Examples of Excellence" be established in lieu of "Best Practices," the survey results included “Best Practices” that were self-nominated by survey respondents. RTBPTF reviewed the nominations and attempted to identify the practices related to tools and/or operating practices that go beyond the minimum requirements of existing standards and are unique to individual organizations but may not be applicable throughout the industry.

The criteria used to differentiate the self-nominated practices and develop the examples listed in this section of the report are as follows:

1. Example must be nominated by either the individual entity or a task force member, and must be approved by both.
2. Example can be assumed to function as stated, i.e., task force will not verify functionality.
3. Recommendations that do not demonstrate an understanding of the tool or a practice discussed in the report will not be considered.
4. Example must be an existing practice, not a desired or planned practice for which empirical results have not been established.
5. Example must be considered not to be commonly used by the majority of the industry; however, the task force will not conduct a side-by-side comparison of each respondent’s practices.
6. Example must be an outstanding practice that the industry could strive to achieve.
7. From survey responses, the task force identified self-nominated “best practices.”
8. Identified best practices were correlated with examples of excellence from NERC readiness audits.

In lieu of conducting face-to-face interviews with the respondents who self-nominated an example of excellence, the task force conducted follow-up email surveys with those respondents. The follow-up surveys consisted of the following questions:

1. Have User fully describe the tool/practice:
    a. What does it do?

b. Who uses it?
c. What are the inputs/outputs?
d. What is the user interface?
e. What is/was the alternative practice?

2. How does it enhance reliability and/or situational awareness?
3. Which reliability standard(s) does it help meet or exceed?
4. What did it take to implement?
5. What does it take to maintain?

Appendix D
Real-Time Tools Survey

The RTBPTF Real-Time Tools Survey questionnaire and the survey results are available at http://www.nerc.com/~filez/rtbptf.html.

Appendix E
Examples of Excellence

Introduction

Real-Time Tools Survey participants were given an opportunity to document a potential example of excellence. RTBPTF reviewed each proposed example of excellence and in some instances requested additional information before deciding to include it in this report. Appendix E presents all the examples of excellence that RTBPTF recommends to the industry for further consideration.

A detailed description of each example of excellence follows, with cross reference to the section of the report in which the example is identified.

Examples of Excellence

EOE-1

Reference — Section 1.1, Telemetry Data
Submitted by — Northeast Power Coordinating Council (NPCC)

Description

RTBPTF has recommended modifications to existing NERC reliability standards with regard to monitoring of bulk electric system elements/parameters. Section 1.1, Telemetry Data, addresses the need to clarify the definition of the term “bulk electric system.” RTBPTF recommends that RCs produce a document called the Bulk Electric System Elements List to specify the elements/parameters monitored within a reliability area. RTBPTF cites the Northeast Power Coordinating Council (NPCC) as an example of excellence in establishing and facilitating a process/methodology for classifying bulk power system elements within the NPCC RRO. NPCC’s “Criteria for Classification of Bulk Power System Elements (A-10)” document (http://www.npcc.org/document/abc.cfm) is used to identify elements to which NPCC bulk power system criteria apply. NPCC’s A-10 Criteria document recognizes that each RC area has an existing list of bulk power system elements.

RTBPTF believes that NPCC’s methodology for classifying bulk electric system elements qualifies as an example of excellence and exemplifies the RTBPTF recommendation of producing a Bulk Electric System Elements List.

Examples of Excellence

EOE-2

Reference — Section 1.2, ICCP-Specific Data
Submitted by — ISO New England

Description

ISO New England and its transmission owners have implemented an automated trouble-tracking system that includes processes and procedures for reporting, notification, tracking, resolution, and escalation of ICCP data problems.

General Information

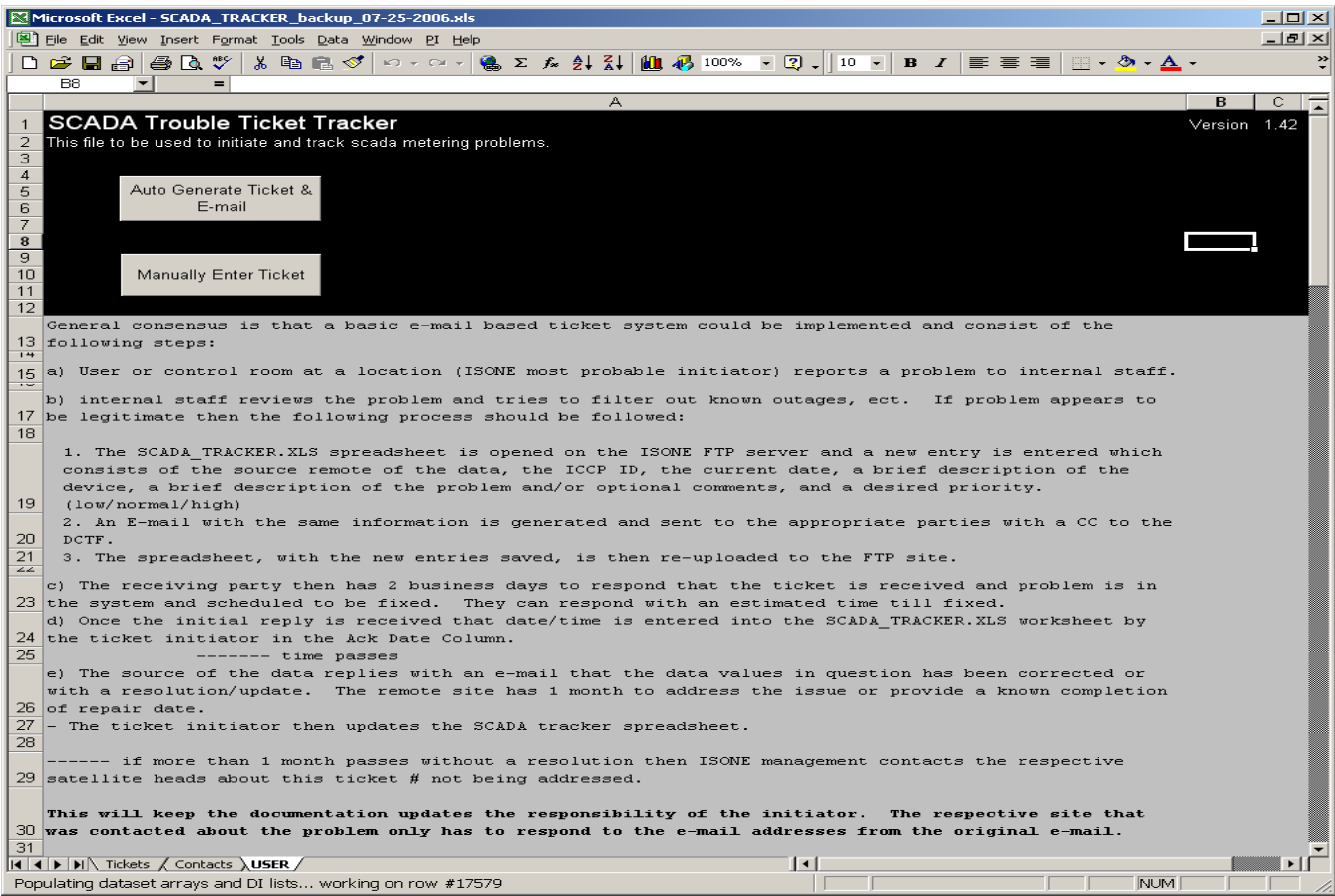
- Tool/Practice Name
  - SCADA TRACKER, a set of procedures, and an Excel spreadsheet system for reporting and tracking the resolution of SCADA data problems related to the New England ICCP network
- Organization Name
  - ISO New England
- NERC Registration (e.g., reliability coordinator)
  - reliability coordinator
  - balancing authority
  - transmission operator
- Contact Name
  - Brock Nubile
- Contact's Official Title
  - Lead EMS Support Specialist
- Contact's Telephone Number
  - 413-540-4210
- Contact's E-mail Address
  - bnubile@iso-ne.com

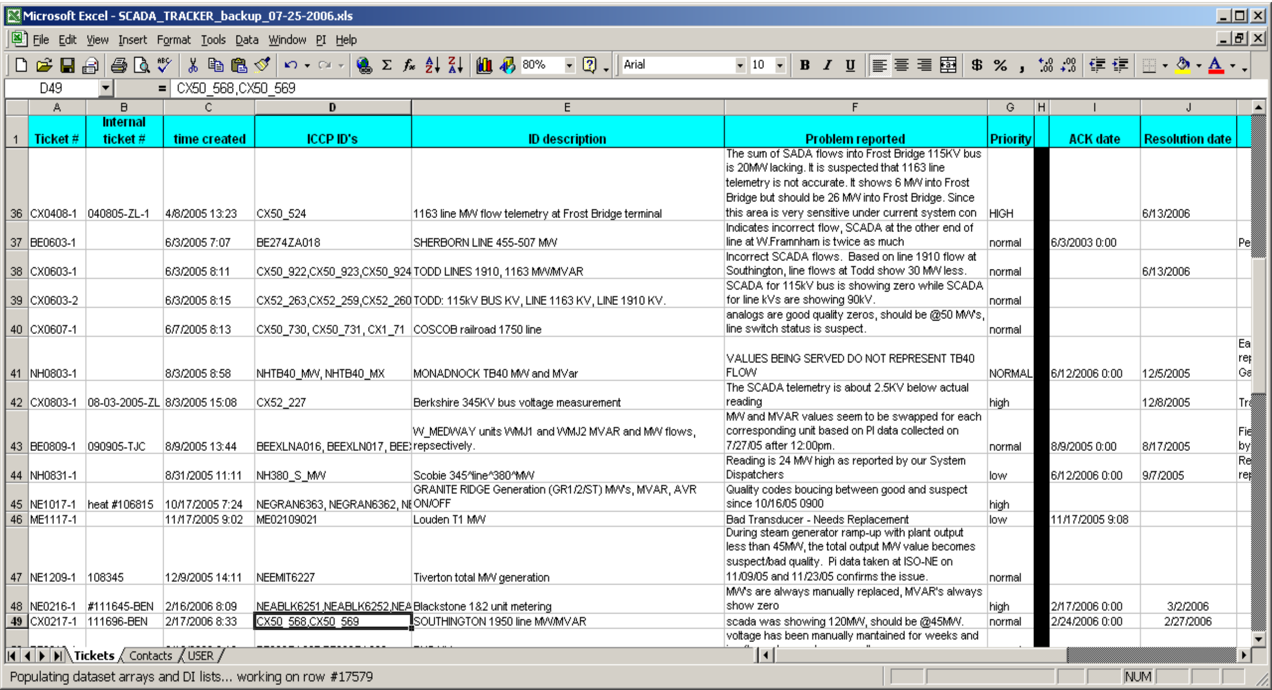
Description of the Tool/Practice

- What does it do?
  - Provides a standard format and procedures for creating trouble tickets related to ICCP SCADA data problems. The Excel spreadsheet contains the procedures, the tracking log, and a set of macros that automatically creates an e-mail message of the ticket to be sent to the appropriate transmission owner/SCADA site. This provides a mechanism for all sites on the network to report data problems that affect all sites on the network. It also provides a log to track resolution of all problems.
- Who uses it?
  - ISO and transmission owner/SCADA EMS support staff
- What are the inputs?

- o Detailed Information about the ICCP data ID with a description of the problem — ICCP ID, data owner, date, problem with the data, and priority rating

- What are the outputs?
  - o Spreadsheet tracking sheet, automatic e-mail message generated
- What is the user interface?
  - o Microsoft Excel spreadsheet; see screenshots below.
- What is/was the alternative practice?
  - o Individual e-mails or phone calls to IT personnel at each site





Microsoft Excel - SCADA_TRACKER_backup_07-25-2006.xls

D49 = CX50_568,CX50_569

	Ticket #	Internal ticket #	time created	ICCP ID's	ID description	Problem reported	Priority		ACK date	Resolution date
36	CX0408-1	040805-ZL-1	4/8/2005 13:23	CX50_524	1163 line MW flow telemetry at Frost Bridge terminal	The sum of SADA flows into Frost Bridge 115KV bus is 20MW lacking. It is suspected that 1163 line telemetry is not accurate. It shows 6 MW into Frost Bridge but should be 26 MW into Frost Bridge. Since this area is very sensitive under current system con	HIGH			6/13/2006
37	BE0603-1		6/3/2005 7:07	BE274ZA018	SHERBORN LINE 455-507 MW	Indicates incorrect flow, SCADA at the other end of line at W.Framnham is twice as much	normal		6/3/2003 0:00	
38	CX0603-1		6/3/2005 8:11	CX50_922,CX50_923,CX50_924	TODD LINES 1910, 1163 MW/MVAR	Incorrect SCADA flows. Based on line 1910 flow at Southington, line flows at Todd show 30 MW less.	normal			6/13/2006
39	CX0603-2		6/3/2005 8:15	CX52_263,CX52_259,CX52_260	TODD: 115kV BUS KV, LINE 1163 KV, LINE 1910 KV.	SCADA for 115kV bus is showing zero while SCADA for line kVs are showing 90kV.	normal			
40	CX0607-1		6/7/2005 8:13	CX50_730, CX50_731, CX1_71	COSCOB railroad 1750 line	analogs are good quality zeros, should be @50 MW's, line switch status is suspect.	normal			
41	NH0803-1		8/3/2005 8:58	NHTB40_MW, NHTB40_MX	MONADNOCK TB40 MW and MVar	VALUES BEING SERVED DO NOT REPRESENT TB40 FLOW	NORMAL		6/12/2006 0:00	12/5/2005
42	CX0803-1	08-03-2005-ZL	8/3/2005 15:08	CX52_227	Berkshire 345KV bus voltage measurement	The SCADA telemetry is about 2.5KV below actual reading	high			12/8/2005
43	BE0809-1	090905-TJC	8/9/2005 13:44	BEEXLNA016, BEEXLN017, BEE	W_MEDWAY units WMJ1 and WMJ2 MVAR and MW flows, repsectively.	MW and MVAR values seem to be swapped for each corresponding unit based on PI data collected on 7/27/05 after 12:00pm.	normal		8/9/2005 0:00	8/17/2005
44	NH0831-1		8/31/2005 11:11	NH380_S_MW	Scobie 345^line^380^MW	Reading is 24 MW high as reported by our System Dispatchers	low		6/12/2006 0:00	9/7/2005
45	NE1017-1	heat #106815	10/17/2005 7:24	NEGRAN6363, NEGRAN6362, NE	GRANITE RIDGE Generation (GR1/2/ST) MW's, MVAR, AVR ON/OFF	Quality codes boucing between good and suspect since 10/16/05 0900	high			
46	ME1117-1		11/17/2005 9:02	ME02109021	Louden T1 MW	Bad Transducer - Needs Replacement	low		11/17/2005 9:08	
47	NE1209-1	108345	12/9/2005 14:11	NEEMIT6227	Tiverton total MW generation	During steam generator ramp-up with plant output less than 45MW, the total output MW value becomes suspect/bad quality. Pi data taken at ISO-NE on 11/09/05 and 11/23/05 confirms the issue.	normal			
48	NE0216-1	#111645-BEN	2/16/2006 8:09	NEABLK6251,NEABLK6252,NEA	Blackstone 1&2 unit metering	MW's are always manually replaced, MVAR's always show zero	high		2/17/2006 0:00	3/2/2006
49	CX0217-1	111696-BEN	2/17/2006 8:33	CX50_568,CX50_569	SOUTHINGTON 1950 line MW/MVAR	scada was showing 120MW, should be @45MW.	normal		2/24/2006 0:00	2/27/2006
						voltage has been manually mantained for weeks and				

Tickets / Contacts / USER

Populating dataset arrays and DI lists... working on row #17579

Reliability/Situational Awareness

- How does it enhance reliability and/or situational awareness?
  - o Improves repair times for SCADA data by getting the appropriate information to the correct staff in a timely fashion
  - o Broadcasts trouble report to all transmission owner sites so all parties are aware of the problem
  - o Provides a tracking mechanism to identify the current status of a data problem and helps identify data values with repeated problem
- Which reliability standard(s) does it help meet or exceed?
  - o IRO-003
  - o IRO-005
  - o TOP-006
  - o TOP-005
  - o COM-001

Support and Maintenance Issues

- What did it take to implement?
  - o Group agreement to parameters and procedures, appropriate contact lists developed, minor macro programming within Excel
- What does it take to maintain?
  - o Enhancements to tool made upon request and review of ISO-NE's Data Communications Task Force
  - o Each submitter must update log with acknowledgment and resolution date

Examples of Excellence

EOE-3

Reference — Section 1.2, ICCP-Specific Data

Submitted by — ISO New England

Description

ISO New England and its transmission owners have implemented an automated monitoring system that periodically compares data set time stamps to detect and alarm any data sets that have stopped updating for any reason.

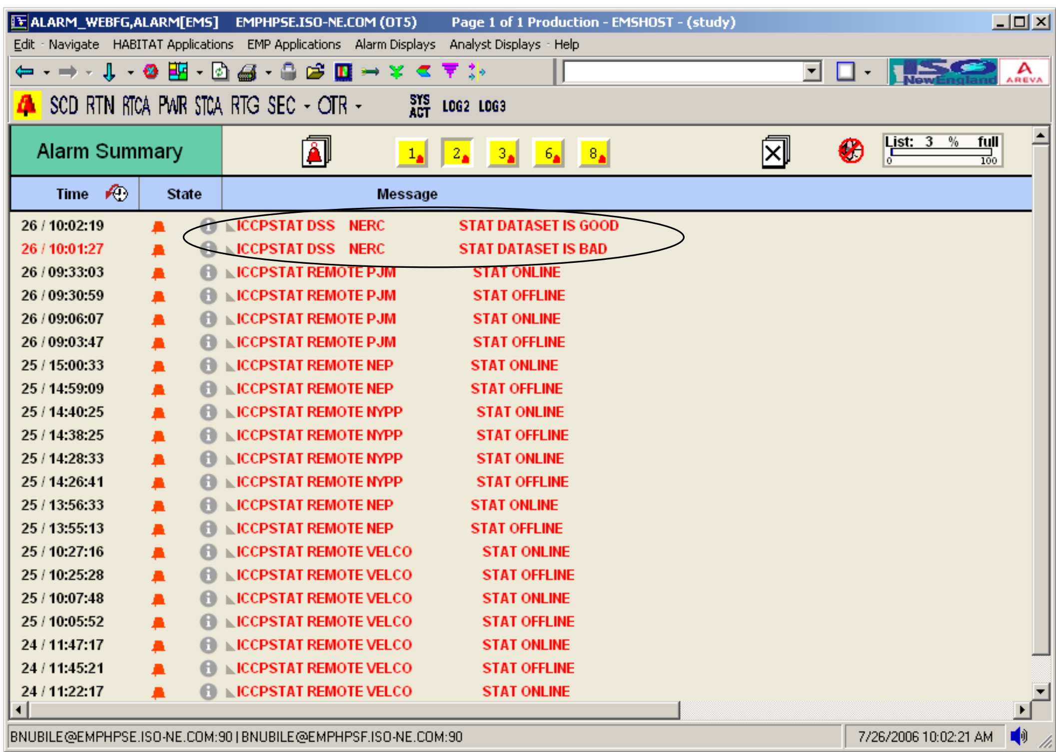
General Information

- Tool/Practice Name
  - DSMON (Data Set Monitor), an in-house designed and written PERL program that monitors all inbound and outbound ICCP server data sets on our vendor-based ICCP servers to confirm that they are transferring data
- Organization Name
  - ISO New England
- NERC Registration (e.g., reliability coordinator)
  - reliability coordinator
  - balancing authority
  - transmission operator
- Contact Name
  - Brock Nubile
- Contact's Official Title
  - Lead EMS Support Specialist
- Contact's Telephone Number
  - 413-540-4210
- Contact's E-mail Address
  - bnubile@iso-ne.com

Description of the Tool/Practice

- What does it do?
  - Every 90 seconds the program dumps a list of all ICCP database data sets and compares the last transfer set time to real time while accounting for the data-set transfer parameters. If delta exceeds a threshold, an alarm is issued to the operators on the EMS. This program detects and alarms any data sets that are interrupted because of:
    - Data-base modeling errors when remote sites perform updates (most common)
    - ICCP application software bugs, memory leaks, or extended run times
    - Severe network problems in which ICCP associations cycle frequently (a failed data set is usually the first symptom)

- Who uses it?
  - o Dispatchers and IT support staff
- What are the inputs?
  - o Vendor-based ICCP database, time-synchronized local ICCP server clock, user-entered run-time periodicity
- What are the outputs?
  - o GOOD/BAD status for each ICCP remote's data sets in the form of an ICCP server log file, vendor-based ICCP server data-base values, EMS-based operator alarms
- What is the user interface?
  - o Native EMS-based alarms
- What is/was the alternative practice?
  - o No alternative; this type of monitoring and alarming not offered by the vendor



Reliability/Situational Awareness

- How does it enhance reliability and/or situational awareness?
  - o Alerts operators and IT staff that large portions of data are not updating even though ICCPLINK is still connected and "UP"
  - o Allows IT staff to pursue correcting problem either locally or remotely
- Which reliability standard(s) does it help meet or exceed?
  - o IRO-003

    - IRO-005
    - TOP-005
    - TOP-006
    - COM-001

Support and Maintenance Issues

- What did it take to implement?
    - PERL programming, data-base additions on ICCP and EMS system, training for operators and support staff to respond to the new alarm
- What does it take to maintain?
    - No special maintenance required

Examples of Excellence

EOE-4

Reference — Section 2.2, Visualization Techniques
Submitted by — Northeast Power Coordinating Council (NPCC)

Description

Tool/Practice Name:	Facilitated Transaction Checkout (FTC)
NERC Registration:	Reliability Coordinator
Contact Name:	John M. Simonelli
Contact's Official Title:	Manager Operations Support Services
Contact's Telephone Number:	(413)535-4157

Overview

Historically, the accuracy associated with transaction checkout between those entities tasked with maintaining reliability has been an important industry issue as recognized by both the NERC Operating Committee and its Interchange Subcommittee. In recognition of the reliability concerns associated with transaction checkout and findings from the August 2003 Blackout, elected to undertake a region-wide effort towards improving transaction accuracy.

The NPCC FTC is a tool implemented by all balancing authorities within the NPCC region. PJM expects to implement FTC in the near future, and MISO expects to implement FTC during the fourth quarter of 2006. The tool is a message structure that enables neighboring reliability entities to query each other's transaction stacks and perform an automated comparison prior to performing verbal checkout. This is accomplished through programmatic data exchange using a standard set of protocols agreed to by the NPCC reliability entities. Because the tool is the communication behind the display, the results can be seamlessly integrated into existing EMS applications. The FTC process provides for the data to be easily integrated into existing displays to meet the unique needs of the different balancing authority operators. FTC does not require third-party intervention or support. The current real-time transaction checkout implementation focuses on transactions between entities using the required NERC e-tag as a common identifier. With slight variations to the standard message structure, the tool can and, in some current instances, is being used for Day Ahead/Day Prior transaction verification, after the fact schedule reconciliation, actual tie information and metered tie flow information for inadvertent checkout.

Detailed Description

Transaction Checkout is a common term for an inter-regional business process employed by neighboring BA operators in the northeast. During the Transaction Checkout process, neighboring BAs communicate in an effort to reconcile the pending net interchange between the individual BAs. The primary objective of the Transaction Checkout process is to reach agreement on a net interchange between BAs as well as the underlying list of individual transactions for the next hour. These transactions may be derived under the auspices of full financial markets or under the traditional physical bi-lateral systems. In either case, operators must cross-reference the transactions scheduled separately by each BA to ensure that for each transaction scheduled out of a given BA, there is a corresponding transaction scheduled into the neighboring BA.

For the majority of the industry, this is currently a manual business process accomplished via telephone communication by BA operators. Moreover, each operator has extremely limited (if any) visibility of other BA transactions. Cycling through lists of transactions and cross-referencing them with the neighboring BAs (ensuring that both sides have the same information) is a lengthy and labor-intensive process. Since the operator of one BA does not have any visibility into the other BA's transaction stack, the operator must review each transaction to ensure that it matches the transactions expected in the neighboring BA. Currently, operators must repeat this tedious and inefficient process every hour, 24 hours per day, 7 days per week. Moreover, with the recent efforts to reduce bidding and scheduling to 15-minute intervals, the current process may prove unsustainable.

Facilitated Transaction Checkout (FTC) is accomplished through programmatic data exchange using a standard set of protocols agreed to by the NPCC balancing authorities (BA). Each BA is responsible for providing a "service" that allows other BAs to programmatically request and receive transaction data in preparation for checkout procedures. It is important to point out that there is no standard FTC application or user interface. Each BA has the flexibility to incorporate the functionality into their existing BA tools as each sees fit.

The NPCC FTC solution provides tangible efficiency gains in the transaction checkout process. Advancing this solution from a concept to implementation required mutual cooperation and collaboration from neighboring Balancing Authorities in the northeast. Continued collaboration among NPCC members and its neighbors, PJM and MISO, was vitally important to collectively define, develop, and implement a robust FTC solution.

The proposed FTC solution is not intended to fully automate the process of checkout, nor is it aimed at eliminating the critical human function of the operator. Instead, it is designed to assist system operators by equipping them with the most complete, accurate and timely data possible. The purpose is to facilitate the checkout process such that it can be accomplished in less time and with greater accuracy. The fundamental high-level business process of reviewing transactions between BAs will remain the same; the FTC solution simply makes it easier to execute.

Looking beyond the implementation of FTC in the northeast, an additional direct and tangible benefit of the FTC effort has been programmatic flexibility. The technology developed to support FTC is now serving as the foundation in the development of several other NPCC-wide applications, such as after the fact Inadvertent Accounting and real-time tracking of Shared Activated Reserves. NPCC's development of new, automated "wide-area" tools continues to improve operator efficiency and overall system reliability.

Examples of Excellence

EOE-5
Reference — Section 2.2, Visualization Techniques
Submitted by — Southwest Power Pool (SPP)

Description

Tool/Practice Name:	PowerWorld Retriever
NERC Registration:	Reliability Coordinator
Contact Name:	Kevin Bates
Contact's Official Title:	EMS Engineer
Contact's Telephone Number:	(501)614-3288
Contact's E-mail Address:	kbates@spp.org

Overview

Southwest Power Pool utilizes PowerWorld Retriever to provide a system overview as well as alarm using pie charts and flashing lines. The contouring of voltage, state estimator versus SCADA, generation MW and Mvar availability has proven to be useful in reliability coordination as well as system performance from a technical staff perspective.

PowerWorld Retriever provides a geographical overview of the SPP Reliability system and its neighboring areas. Visualization effects include:

- Arrows depict direction and magnitude of line flow
- "Blinking" lines indicate real-time out-of-service elements
- Pie charts alarm for real-time overloads
- Voltage is contoured

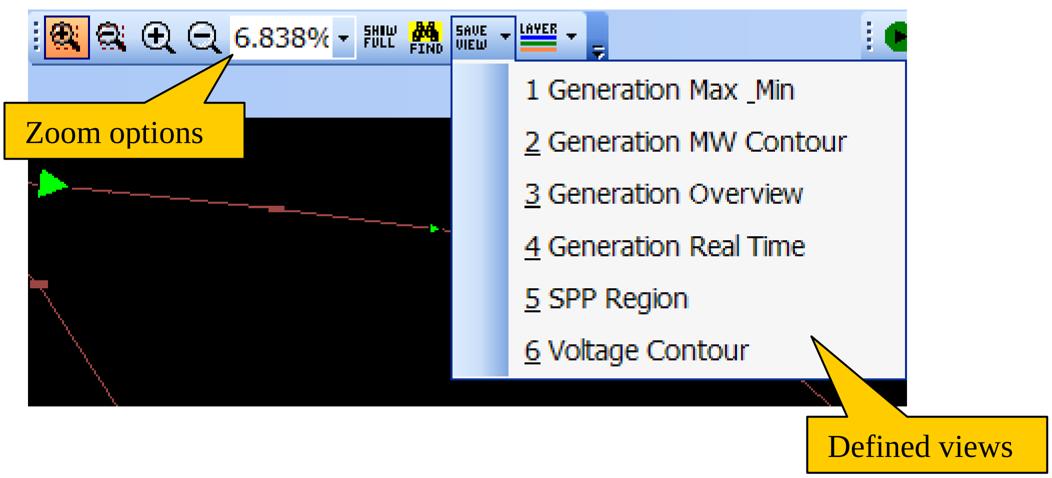
Detailed Description

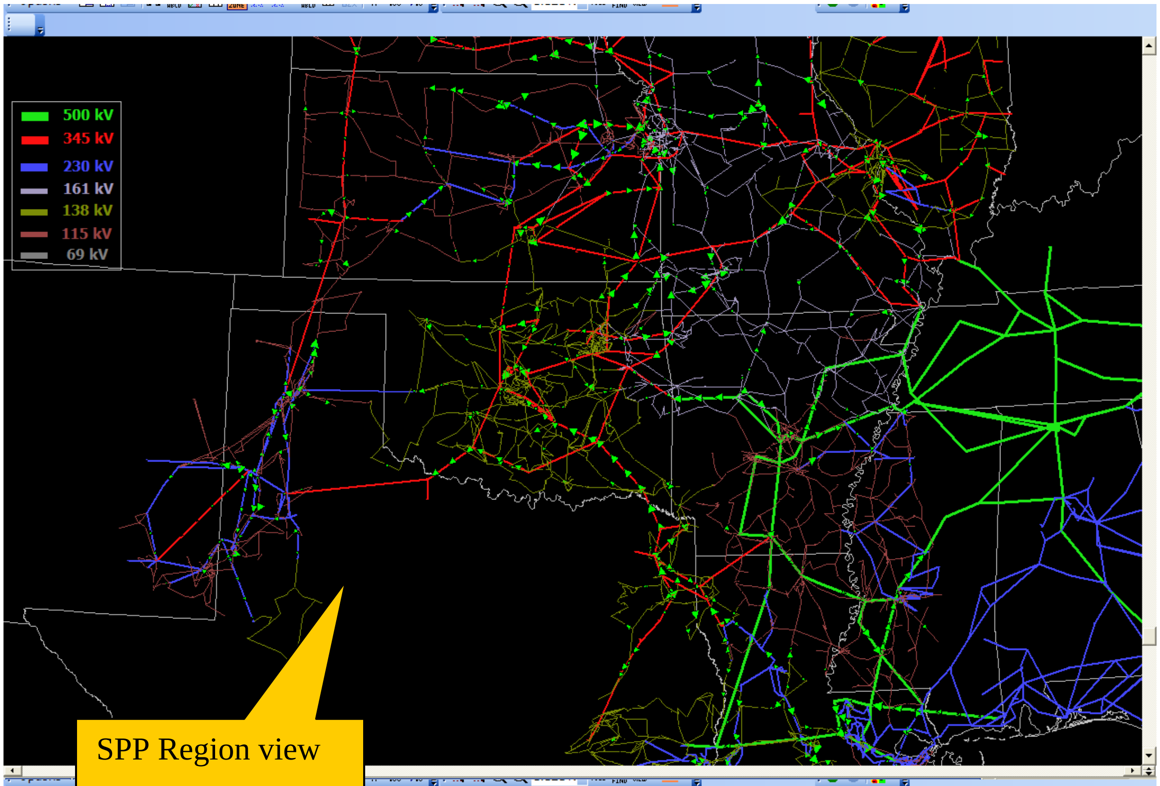
RCs use PowerWorld Retriever as a situational awareness tool in real-time operations as well as training situations. EMS engineers have also used PowerWorld Retriever for contouring differences between SCADA and the state estimator. Since the PowerWorld Retriever model is derived from the EMS model, PowerWorld Retriever has also been used for model verification.

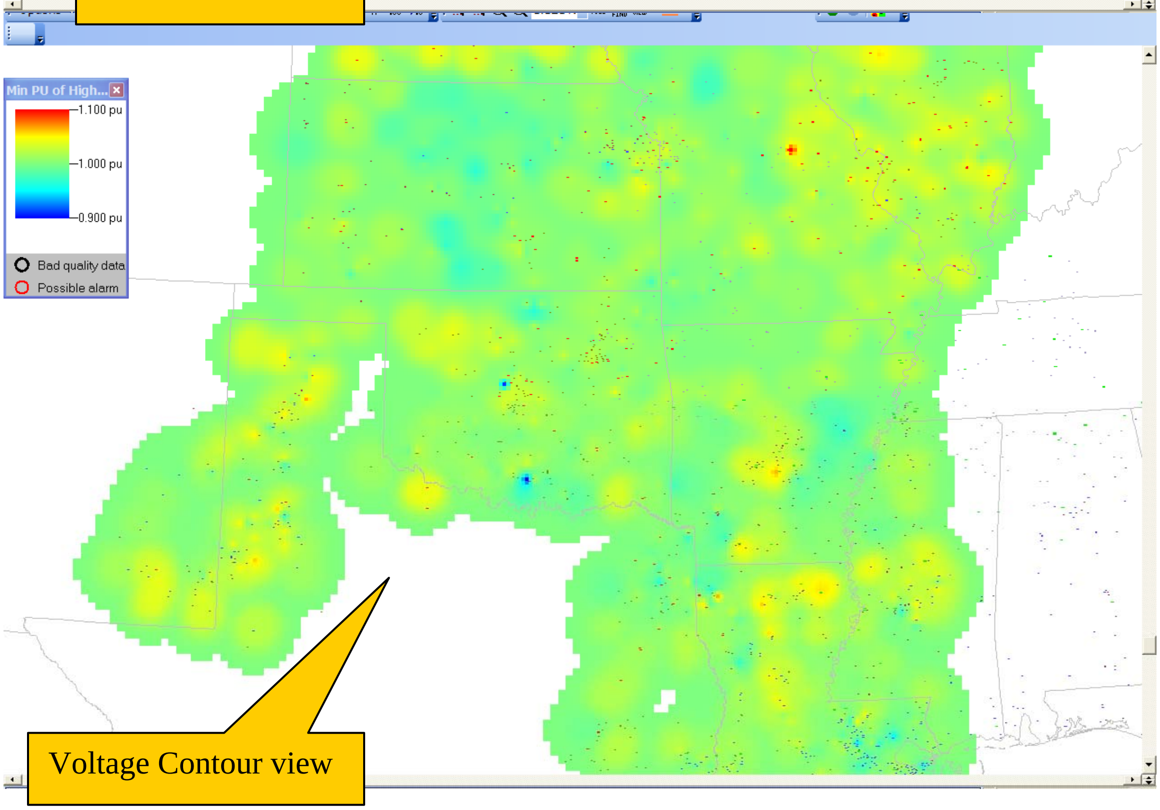
The PowerWorld Retriever model is constructed using the EMS NETMOM model exported via the EMS modeling tool, Genesys. Programs residing on the EMS export SCADA data every 30 seconds and state estimator data every 1 minute from the EMS to text files. Because real-time status for elements is not available from all sources via ICCP, these elements (lines, transformers, generators) have real-time status points defined using real-time status of associated breakers and switches. These points and analogs are placed in flat text files along with a unique alias that identifies a value in the PowerWorld Retriever model. Configuration files loaded to PowerWorld Retriever upon initialization include subscriptions that provide the “links” between these aliases and the PowerWorld Retriever model data fields. These text files can be generated from any EMS system (production, backup, development, etc.), so PowerWorld Retriever can be utilized in training scenarios as well.

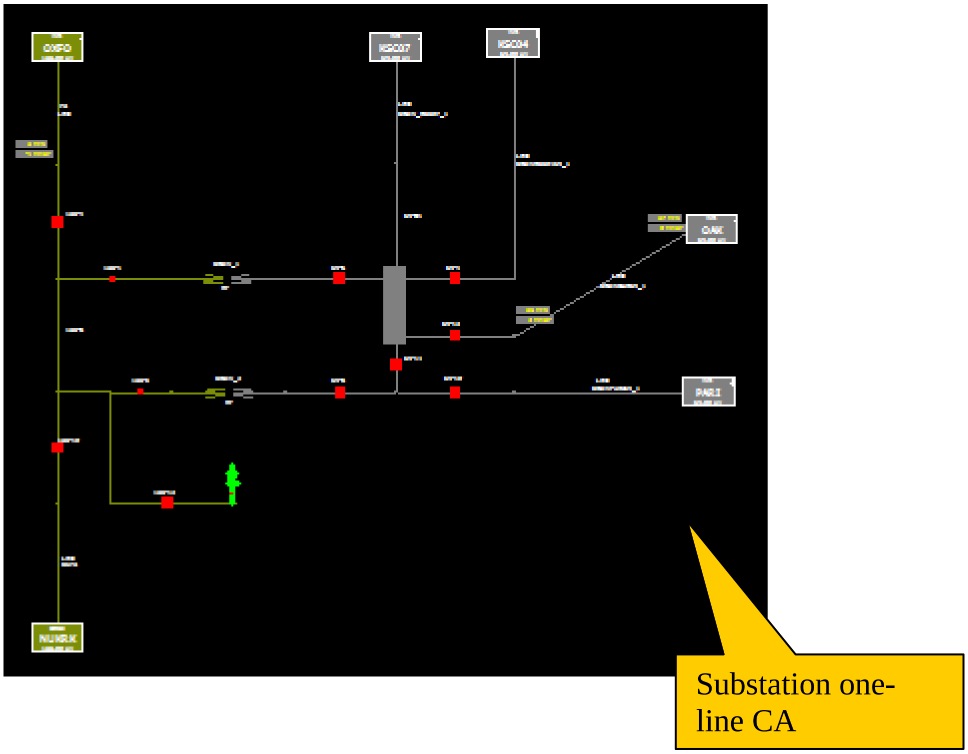
No data outputs are generated by PowerWorld Retriever other than update logs. The data inputs to the model are displayed on associated one-lines which may be geographic or schematic. The aforementioned features (blinking lines, line flow arrows, etc.) are displayed on one-lines that are associated with the underlying model. The text file inputs can be configured to link to any EMS system, therefore resulting in displays showing data from systems used for production, training, or testing.

The interface is typical pull-down menus and toolbars. The most common features used by RCs include navigation tools such as zoom, pan, find, etc. Because of the vast options available, saved views are used to easily navigate between desired displayed data on one-lines. These views have position and layers turned on/off so users are one click from desired views. Case Information tables provide model information and options for sorting, filtering, and exporting. Some substation one-lines are available.




500 kV
345 kV
230 kV
161 kV
138 kV
115 kV
69 kV
SPP Region view


Min PU of High...
1.100 pu
1.000 pu
0.900 pu
Bad quality data
Possible alarm
Voltage Contour view



All data displayed in PowerWorld Retriever are available using EMS displays. They are not depicted in a geographic overview but rather a bus/branch or tabular list. With this tool, RCs are made aware of voltage conditions, real-time flows, and outages for the SPP Region and adjacent regions, which enhances their situational awareness. PowerWorld Retriever helps SPP meet Standard IRO-003-0 by providing a wide-area view of the SPP RC Area and the areas of neighboring RCs.

PowerWorld Corporation was contracted to develop the initial model and overview one-line. SPP and PowerWorld staff integrated an export of the SPP EMS model to the PowerWorld Retriever model structure. Also developed with cooperation of PowerWorld staff were alias and subscription formats used in linking data from the EMS to the PowerWorld Retriever model. SPP also developed programs to export SCADA, state estimator, real-time contingency analysis, and outage scheduler data into text files for uploading to PowerWorld Retriever. Some clean-up and customization of the overview one-line was performed as well as of the view definitions.

Maintenance is performed with each upload of a new EMS model or as needed for modeling corrections. Text files with pertinent modeling information are exported using Genesys. Because PowerWorld Retriever's model structure uses bus numbers that do not correlate with a bus number from the EMS model, a Microsoft Access database is used to maintain consistency between models. This prevents renumbering of one-lines during bulk uploads of a new model. Only new or deleted devices need addressed on associated one-lines. This database also allows for export of aliases and subscriptions used for compiling configuration files used by PowerWorld Retriever.

Examples of Excellence

EOE-6
Reference — Section 2.2, Visualization Techniques
Submitted by — Midwest ISO

Description

Tool/Practice Name: Wide-Area Overview
NERC Registration: Reliability Coordinator

Overview

MISO implemented an expansive wide-area overview display with underlying BA and one-line displays. MISO also incorporated the following into its visualization tools:

- A flowgate monitoring tool that uses LODFs calculated every 10 seconds. This display also includes a provision for dynamic ratings or operating guides.
- A set of reactive monitoring display "delta" tools that visualize sudden changes in generator output or transmission facility flow.

Examples of Excellence

EOE-7
Reference — Section 2.2, Visualization Techniques
Submitted by — American Transmission Company

Description

Tool/Practice Name:	Wide-Area Overview
NERC Registration:	Reliability Coordinator

Overview

ATC utilizes an application that interfaces directly with its EMS to provide system operators with a dynamic wide-area overview of ATC's network topology as well as state estimation of the neighboring systems. The one-line display (wide-area overview representation) is created automatically from the data within the network model (internal and external). When new equipment is added, the wide-area overview display automatically updates. The wide-area overview provides the operator with actual flows, indications of open lines, and visual indication for lines approaching thermal limits. ATC's operators can dynamically select what is displayed, zoom in or out, and pan across the system. In addition to displaying a wide-area overview, system operators can filter, sort, and query the data to better analyze the power system.

Examples of Excellence

EOE-8

Reference — Section 2.5, State Estimator
Submitted by — Midwest ISO

Description

Tool/Practice Name: State Estimator
NERC Registration: Reliability Coordinator

Overview

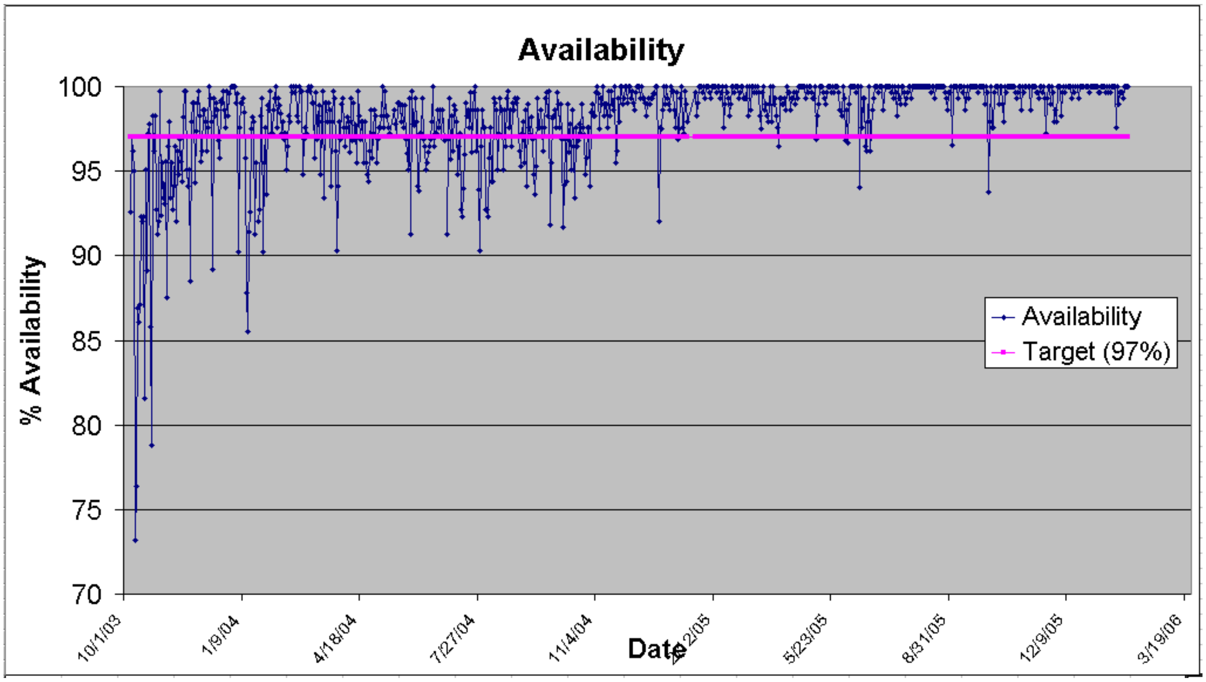
MISO has developed a state estimator solution summary spreadsheet that is used to track solution availability and solution-quality metrics such as solution mismatch, status, convergence, and error tracking for select branch flows, bus voltages, and tie-line flows.

Detailed Description

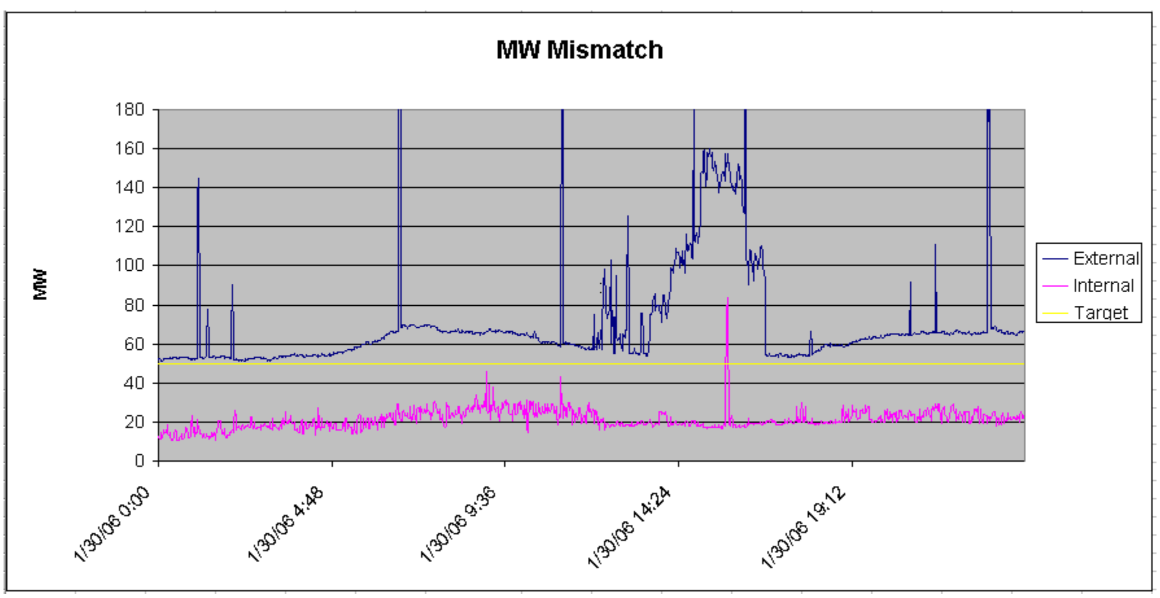
The “home page” of the summary is shown below and includes explanations of what each metric represents.

SE Solution Summary	**01-30-2006** **12:00:00 AM - 11:59:59 PM** Import Data Into Spreadsheet	
State Estimator Metrics Plots	**Plot Explanation**	
State Estimator Availability	**MISO and Transmission Owners require 97% availability. This metric describes the number of 5 minute periods in a day that had a state estimator solution. In a day there exists 288 5 minute periods, to reach 97% availability MISO needs to have state estimator solutions for 280 or more of those periods.**	SE Availability Plot
State Estimator Solution Mismatch	**MISO and Transmission Owners require < 50 MW mismatch for all companies within the MISO footprint. The mismatch data reported here illustrates solution mismatch for both internal and external companies.**	SE MW Mismatch Plot
State Estimator Solution Status	**Illustrates the solution status for each 5 minute period over a 24 hour period. A point of "1" indicates a valid solution period. A point of "0" indicates that no valid solution occurred during that five minute period.**	SE Solution Status Plot
State Estimator Voltage Convergence	**MISO tracks the state estimator voltage convergence on a solution basis. MISO and the Transmission Owners require the state estimator to run with voltage and/or angle convergence tolerances of 0.002, and maximum MW mismatch of 50 MW.**	Voltage Convergence
50 Flowgate, 10 Tie Line, 30 Bus Metrics	**MISO monitors a list of 50 flowgates, 10 external tie lines, and 30 critical bus voltages. These plots illustrate the % error of the solved value compared to the measured**	50 Flowgate, 10 Tie Line, 30 Bus Metrics

The SE availability plot is shown below. It reveals a dramatic increase in the availability of the state estimator as MISO made preparations for the opening of the market. Market applications depend on accurate and highly available solutions from the state estimator to support locational marginal pricing and congestion management.



The MW mismatch plot shown below illustrates how well the total mismatch for companies within the MISO footprint is kept within the target value.



The availability and solution quality metrics illustrated above as well as others that MISO has developed are excellent examples of the types of state-estimator performance metrics that should be monitored as part of the pilot program recommended above. MISO has clearly demonstrated that it is desirable and practical to develop such metrics.

Examples of Excellence

EOE-9
Reference — Section 2.6, Contingency Analysis
Submitted by — Entergy Corporation

Description

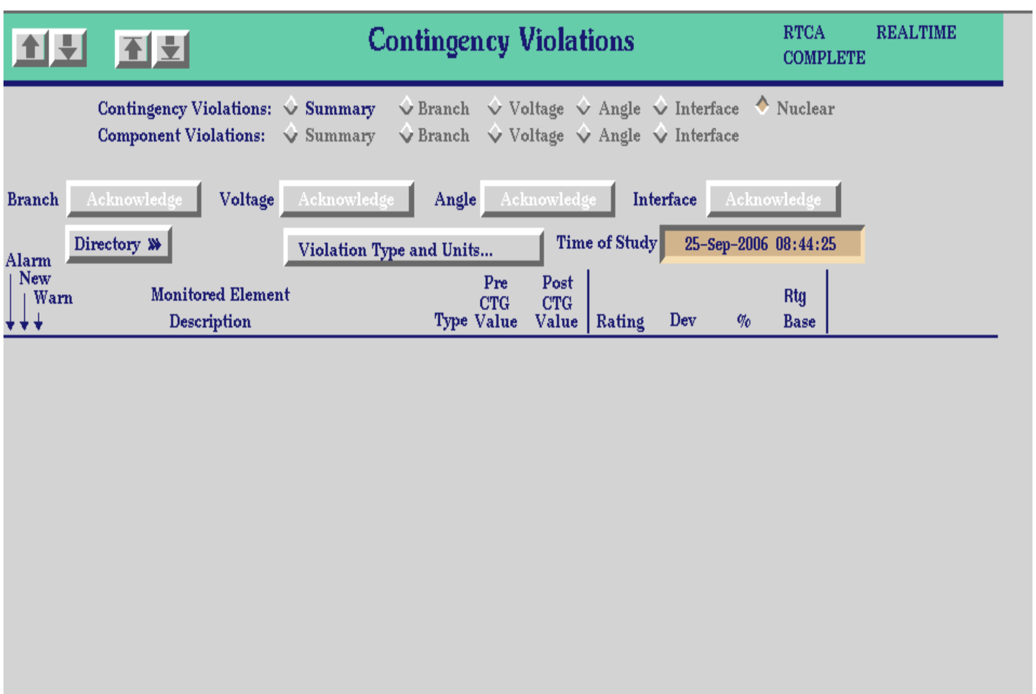
Tool/Practice Name	Utilization of RTCA in Nuclear Offsite Power Monitoring
NERC Registration	Reliability Coordinator, Transmission Operator, Balancing Authority

Overview

Entergy has a real-time contingency analysis application that accurately simulates the effects of loss of a nuclear power plant on switchyard voltage.

Detailed Description

The loss of a nuclear power plant results in the station service load being completely fed by offsite power. To simulate these events accurately, Entergy modified the contingency definitions to add plant load in the event of NPP trip. The real-time contingency analysis at Entergy's control center simulates approximately 1,700 contingencies. To isolate the violations related to NPP offsite power, Entergy also created a separate display that only shows the NPP violations. The following screenshot shows the customized display.



Entergy also developed detailed procedures and operating guides for reporting and acting on NPP offsite power violations. The procedures are summarized below:

Steps to Responding to Violations

Steps 1–3 should be performed within 30 minutes.

1. Verify the validity of the Real-Time Alarm or Post-Contingent Violation.
   a. It is extremely important that all violations are validated prior to continuing with this process.
2. Create State Estimator (RTNET) Save Case to document the violation. The case name should be: “Nuclear_Violation_mm_dd_yyyy_hh_mm”

3. Check the state of the transmission grid for a possible mitigation plan.
   a. Determine if there are any capacitors or reactors in the area that would help relieve the violation.
   b. Determine if there are any transmission equipment outages in the area that are having an impact on the violation.
   c. Determine if there are any generators (Other than the Nuclear Generator) that can be utilized to help relieve the violation. ***The Nuclear Generator can be called to assist with relieving HIGH Voltage, but should NOT be utilized to relieve LOW Voltage.
4. Develop and execute the mitigation plan. This mitigation plan should be capable of relieving the violation without having a negative affect on the reliability of the transmission system. Steps 1-3 must be completed within 30 minutes following the violation.
5. Report the violation to the respective nuclear plant using the following form (Regardless of whether or not the mitigation plan corrected the violation).

   This form should be faxed to the respective nuclear plant and followed up with a phone call to verify the receipt of the fax.

6. If the violation was NOT corrected, proceed to step 7. If the violation WAS corrected no further action will be required. However, be prepared to answer questions from nuclear personnel regarding the violation.

   Fax updated Online Notification Form to the Respective Nuclear Plants and follow up with a phone call to verify the receipt of the fax.

7. If the mitigation plan fails to relieve the violation within 30 minutes or a mitigation plan could not be determined within 30 minutes, contact the on-call support personnel, on-call Duty Chief and the Reliability Coordinator to make them aware of the situation.

   Fax updated Online Notification Form to the Respective Nuclear Plants and follow up with a phone call to verify the receipt of the fax.

8. **Nuclear Conference Call:** If a violation still exists, the nuclear plant will set up a conference call with nuclear and transmission. Once the system operation center (SOC) has been notified of the conference call time by nuclear, the SOC Shift Supervisor will be responsible for notifying the following transmission personnel of the conference call. ***To notify this group you will need to send a page to the "Nuclear Notification" Group using the following text: ***Name, Phone Number***. Nuclear Offsite Voltage Notification made on ***mm/dd/yyyy*** at ***HH:MM***. Conference call will begin at ***HH:MM***. Phone Number: **###-###-####**. Access Number: **#####**

    - Transmission Operational Planning Representative
    - SOC Duty Chief
    - Operations Director
    - System Security - Manager
    - Reliability Coordinator
    - Reliability Coordinator Support
    - TOC Manager for area of discussion

9. Following the conference call, the SOC Shift Supervisor will be responsible for the execution of any additional transmission actions as well as continuing to monitor the violation.

   Fax updated Online Notification Form to the Respective Nuclear Plants and follow up with a phone call to verify the receipt of the fax.

10. Once the violation has ended, the SOC Shift Supervisor will be responsible for sending the nuclear plant the completed Nuclear Notification form and notifying all transmission personnel involved of the end of the violation.

    The form should be faxed to the respective nuclear plant and followed up with a phone call to verify the receipt of the fax.

11. Create State Estimator (RTNET) Save Case to document the violation. The case name should be: "Nuclear_Violation_mm_dd_yyyy_hh_mm"

The process also requires operators to monitor availability of real-time contingency analysis and the state estimator. Entergy also established a procedure to notify nuclear power producers in the event of unavailability of real-time contingency analysis or the state Estimator. The procedure is outlined below. These procedures are only applicable for notifying nuclear plants.

Steps to take when the state estimator is unavailable:

1. Document the time that the state estimator became unavailable. Report the unavailability to EMS on call person.
2. Can the state estimator be restored in <1 Hour?

a. **YES:** Continue to monitor on how long the state estimator has been down. If the restoration time exceeds 1 Hour, proceed to step 2b.

b. **NO:**

  i. Contact the on-call Operations representative.

    1. Verify that the Offline Nuclear Monitoring System is available.
    2. Discuss any unplanned system changes that have occurred since the last time Operations ran the nuclear offline study.[8] If changes have occurred, request that Operations rerun the nuclear study to check for any issues.

  ii. Verify that the SOC EMS system is functioning.

    1. **If SOC EMS System is <u>NOT</u> functioning:** Contact each Transmission Operation Center (TOC) that has a nuclear plant within its system and request that it notify the SOC if any low-voltage alarms are received at any substation near the nuclear plant. Proceed to iii.
    2. **If SOC EMS System <u>IS</u> functioning:** Continuing to monitor for any nuclear voltage alarms. Proceed to iii.

  iii. Notify each nuclear plant using the following form.

  This form should be faxed to the respective nuclear plant and followed up with a phone call to verify the receipt of the fax.

3. After the state estimator has retuned to service and the SOC EMS is functioning correctly.

  a. If the nuclear plants were previously contacted in the above step, notify each nuclear plant using the same form as above.

  The form should be faxed to the respective nuclear plant and followed up with a phone call to verify the receipt of the fax.

  b. If the SOC EMS System was not functioning correctly and the TOCs were requested to monitor real-time voltage alarms around the nuclear plants, contact the TOCs and inform them that the SOC EMS System is now functioning correctly.

[8] Entergy has also implemented an offline process to monitor the nuclear power plant offsite power for next day.

Examples of Excellence

EOE-10
Reference — Section 2.7, Critical Facility Loading Assessment
Submitted by — PJM

Description

Tool/Practice Name: Thermal Tracking
NERC Registration: Reliability Coordinator

Overview

The Thermal Tracking (TT) critical facility loading assessment nominated by PJM was originally supplied as a standard part of their EMS vendor software but has been subsequently enhanced by PJM. TT is used to screen for transfer interface violations and a number of potentially serious double-contingency violations. Of particular value is the enhanced capability for this application to advise operators of the generation redispatch options to alleviate reported overloads. This tool also acts as a backup should the first-line security analysis functions abort or otherwise degrade.

Examples of Excellence

EOE-11
Reference — Section 2.9, Study Real-Time Maintenance (SRTM)
Submitted by — PJM

Description

Tool/Practice Name:	Study Real-Time Maintenance
NERC Registration:	Reliability Coordinator

Overview

PJM Regional Transmission Operator (RTOP) can host up to three users of the SRTM function simultaneously in the production EMS environment. The function is typically performed by support staff, not operators. To avoid conflicts, each user of the SRTM function is completely independent of the production real-time system and of any other SRTM users. Each SRTM user interface looks and feels exactly like the production network applications. However, instead of the red window border used to indicate the production real-time system, a green window border is used to clearly distinguish that the user is actually in SRTM mode.

Historical real-time state estimator saved cases are archived automatically every 5 minutes. All non-converged state estimator solutions are archived automatically when they occur. An SRTM user can be initialized from a historical saved case or the current real-time state estimator solution within seconds. All real-time network applications including NTP, CFLA, flowgate distribution factor calculation, state estimator, contingency analysis, and voltage stability are initialized from the saved case or the current real-time solution. All real-time network applications can be run exactly as they were in the real-time production EMS environment; therefore, all problems and results can be reproduced for debugging purposes. An SRTM case can be archived by the user and retrieved at a later time to complete work. An SRTM case can be used to initialize a study power-flow user, in the same manner as from a real-time state estimator case, to simulate the study network applications.

It is important to note that an old case archived from a previous version of the network model may not be compatible with the current version of the network model depending on the number and type of model changes. To avoid this problem, PJM debugs problems as soon as possible after they occur and prior to updating the network model on the production system if possible. If the model has to be updated prior to resolving a problem, the case is used on a non-production EMS system with the previous version of the network model to complete the work. The PJM practice is to debug and resolve all non-converged state estimator solutions, all non-converged contingency analysis solutions, and all non-converged voltage stability solutions using SRTM as quickly as possible.

In addition, any other network application problems identified by PJM staff are debugged and resolved as quickly as possible using SRTM.

SRTM allows PJM to quickly and easily recreate, debug, and resolve network application problems without impacting the real-time network applications and has increased the overall availability of the real-time network applications. The PJM SRTM was provided by the PJM EMS vendor with some customization. Significant initial testing was required to insure that the initialization software was operating correctly to insure that SRTM results exactly matched the production system. The PJM EMS network applications support staff are the primary users of the SRTM. The PJM system operators, reliability engineers and other engineering support staff also use the SRTM. Because SRTM is fully integrated with the production EMS system, it requires little additional maintenance.

Examples of Excellence

EOE-12
Reference — Section 2.10, Voltage Stability Assessment
Submitted by — PJM

Description

Tool/Practice Name:	Real-time Voltage Stability Application
NERC Registration:	Reliability Coordinator

Overview

PJM is working on an enhanced real-time voltage stability application to provide control actions to avoid collapse and increase stability margins.

Examples of Excellence

EOE-13
Reference — Section 2.14, Other Tools (Current and Operational)
Submitted by — Bonneville Power Administration

Description

Tool/Practice Name:	Congestion Management Application
NERC Registration:	Balancing Authority, Transmission Operator

Overview

The Bonneville Power Administration (BPAT) uses a curtailment wizard in its implementation of a congestion management application. This wizard is an effective and key component of BPAT's congestion management tool for the interties. Schedule adjustments are communicated and coordinated among the affected parties via the e-tag. For the network, BPAT has an "interim" curtailment calculator, which targets specific generation and loads. This curtailment calculator can be used on two of the network flowgates. This is an "in-hour" tool and it works effectively by targeting specific generators and loads. However, it lacks a prospective view of upcoming flows and does not support preventing transmission sales that would further exacerbate the congestion. BPAT is currently planning to integrate e-tag curtailments with these "interim" curtailment calculators while pursuing tools to provide a full capability to manage capacities and congestion on their network.

Examples of Excellence

EOE-14

Reference — Section 2.14, Other Tools (Current and Operational)
Submitted by — FirstEnergy (FE) and MISO

Description

Tool/Practice Name:	Real Power-Voltage Stability Analysis Tool
NERC Registration:	Reliability Coordinator, Transmission Operator

Overview

Excerpted from survey comments by an FE representative:

> An operator must maintain an awareness at all times of where the system is operating relative to all limits. FE, in conjunction with the Midwest Independent Transmission System Operator (MISO), utilizes a real power-voltage (P-V) stability analysis tool that determines system operating limits in three critical areas of the FE transmission system. NERC commended the FE/MISO approach to voltage stability analyses as an Example of Excellence in their November 2, 2005 Reliability Readiness Audit and Improvement Program**.**
>
> P-V analysis is used to determine the health of the system by determining the rate of voltage decay at a system bus as the level of real power changes due to system loads or transfers across the system. The “nose” of the P-V curve represents the maximum real power load that can be served or the amount of power that can be transferred beyond which the rate of voltage decay dramatically increases toward voltage collapse. The difference between the real power quantity being monitored in real time and the real power limit at the nose of the curve is the real power operating margin. The MISO reliability coordinators and FE transmission operators monitor the flow on the three critical interfaces in real time to the lower of the voltage collapse limit, the steady-state voltage limit, and the thermal ratings limit. To provide a sufficient operating margin, MISO and FE apply a ten percent power flow safety margin in the next-day analysis and a five percent margin for the current-day analysis in determining the voltage collapse limit the operators will use. Additional analysis is conducted any time a critical facility in the FE area is out of service. For forced or emergency outages, a MISO operations engineer position is staffed around the clock to perform the analysis.

Examples of Excellence

EOE-15
Reference — Section 3.5, Load-Shed Capability
Submitted by — Dominion Virginia Power

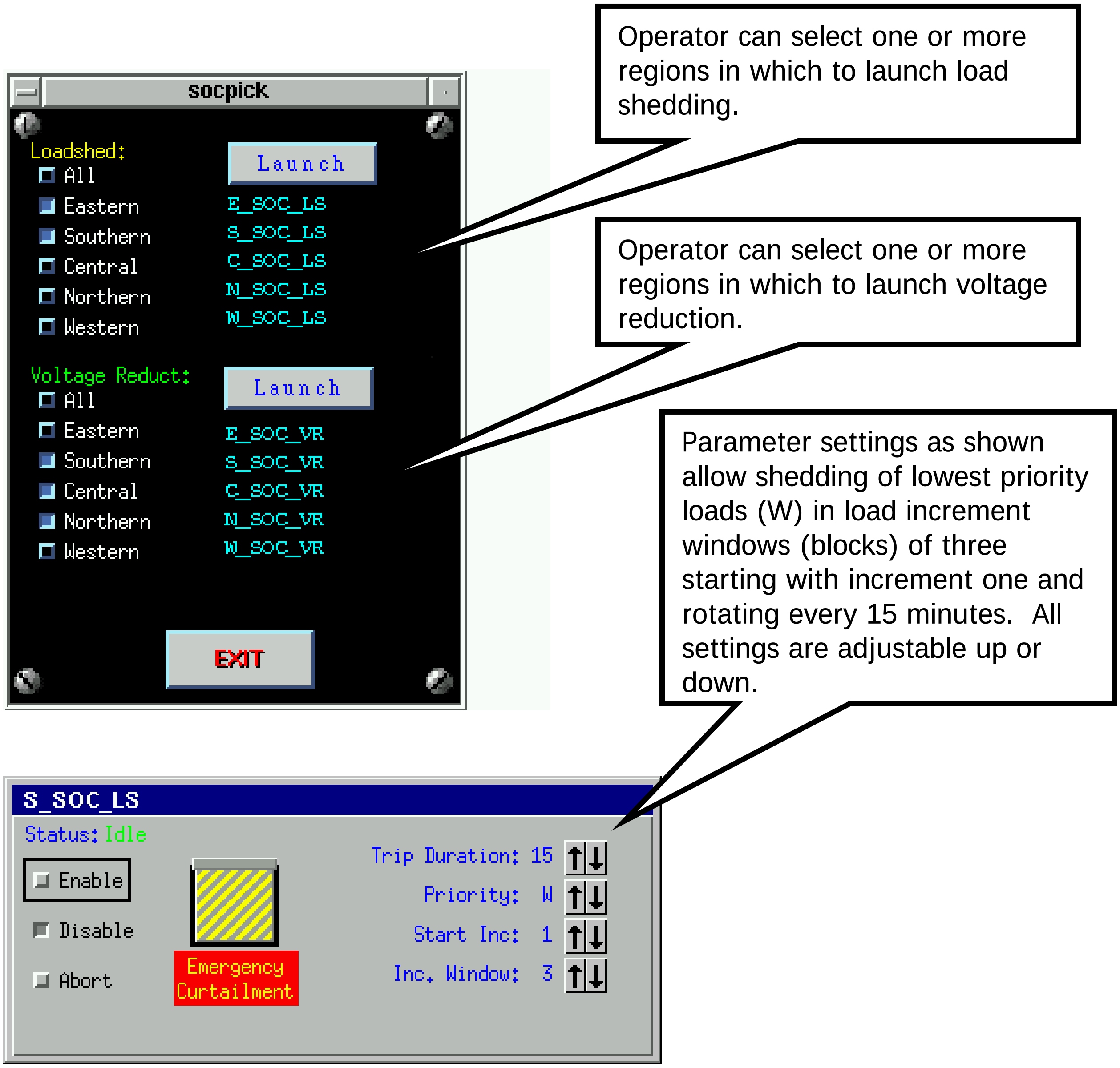
Description

Tool/Practice Name:	Load Shedding/Rotation and Voltage Reduction
NERC Registration:	Transmission Operator

Overview

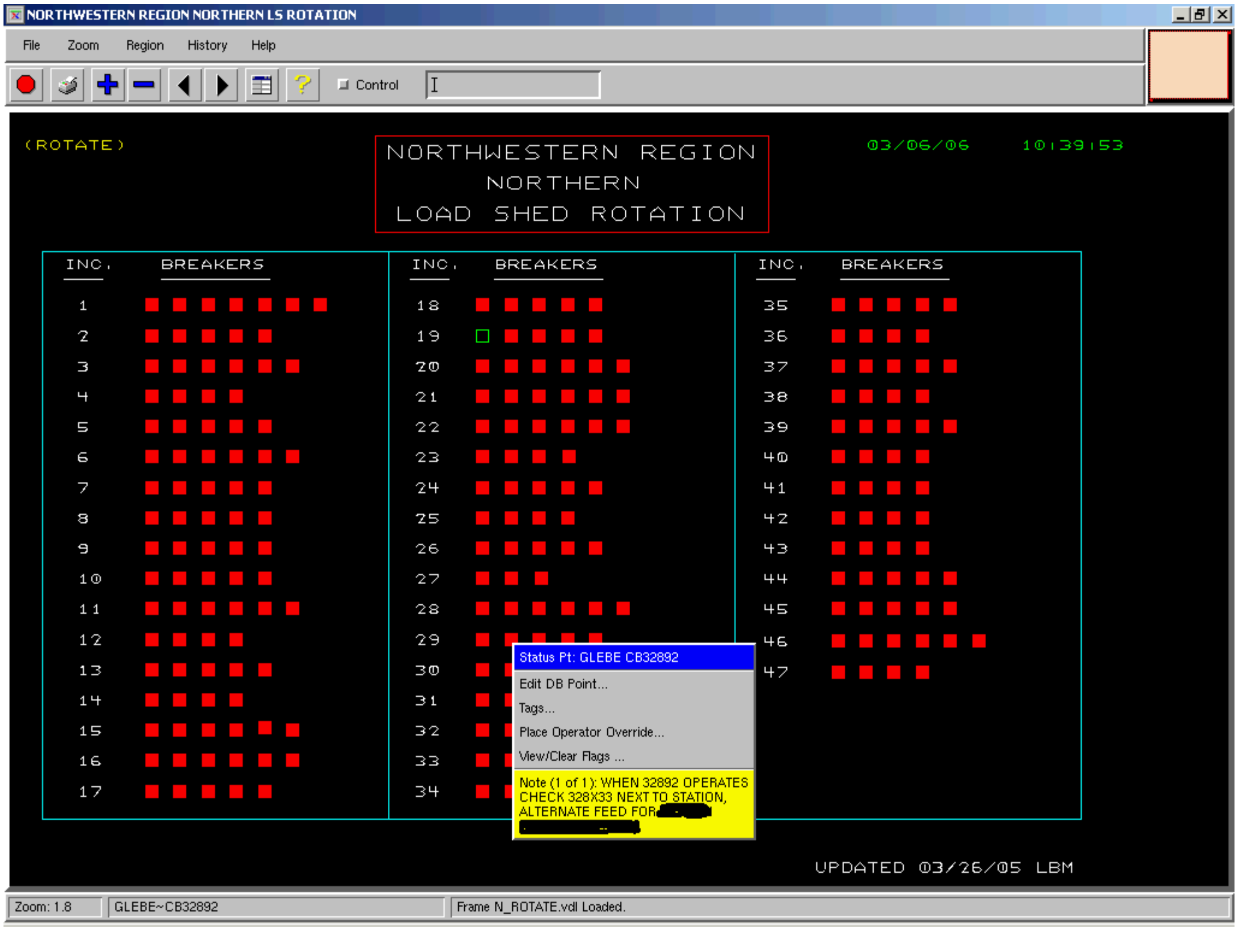
In order to quickly activate the Dominion Virginia Power Load Curtailment Plan, a control application was developed by Dominion to implement load shedding/rotation and voltage reduction. This application runs on the Distribution Management System (DMS), which was developed in house. The application is available to the transmission system operators at the SOC and is also available to the operators at the regional Distribution Operations Centers (DOCs). The program that allows the SOC to implement load curtailment is called SOCpick, and the program that allows the DOC to implement load curtailment is called Loadpick. The main difference between the two programs is the operator interface.

The transmission system operators at the SOC are responsible for implementing load shedding and voltage reduction at the direction of the RC. They can perform this function from their user interface at the SOC or they can request assistance from the regional operators in the three DOCs. The following screen shots show the SOCpick user interface for launching a system-wide or regional load-shed operation or voltage reduction and the user interface for adjusting the load-shed program parameters including trip duration, load priority (W — the lowest, X, Y, or Z — the highest), starting load increment, and load increment window.

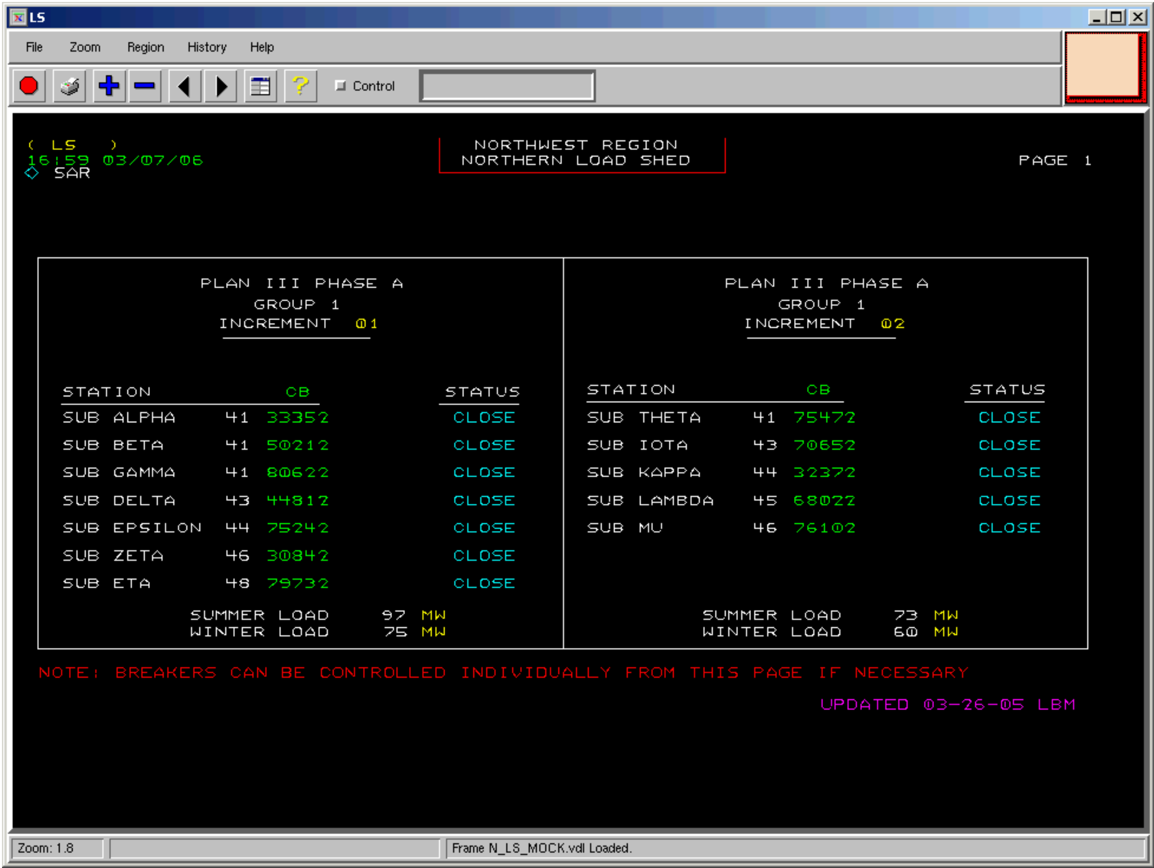


The following screen shot shows the status of each distribution breaker in each load-shed increment (block) in the northwestern region. There are a total of 47 increments in this particular region. In addition to showing the open/close (green/red) status of each breaker, placing the cursor over the breaker symbol generates a pop-up window that identifies the associated substation, breaker number, and other specific information related to the status of the circuit. Any breaker that has a tag on it will have a “T” appear next to it on this screen, and any breaker with a special note associated with it with will have an “N” appear next to it. In the example below, the “N” next to the breaker for circuit 32892 at the Glebe substation is obscured by the pop-up window that identifies the breaker. The pop-up also includes an operating note (redacted for security reasons) highlighted in yellow.

Not only can the status of individual circuits be monitored at any time from this screen, but once load shed is implemented, the progress of load-shed rotation can be monitored as well.

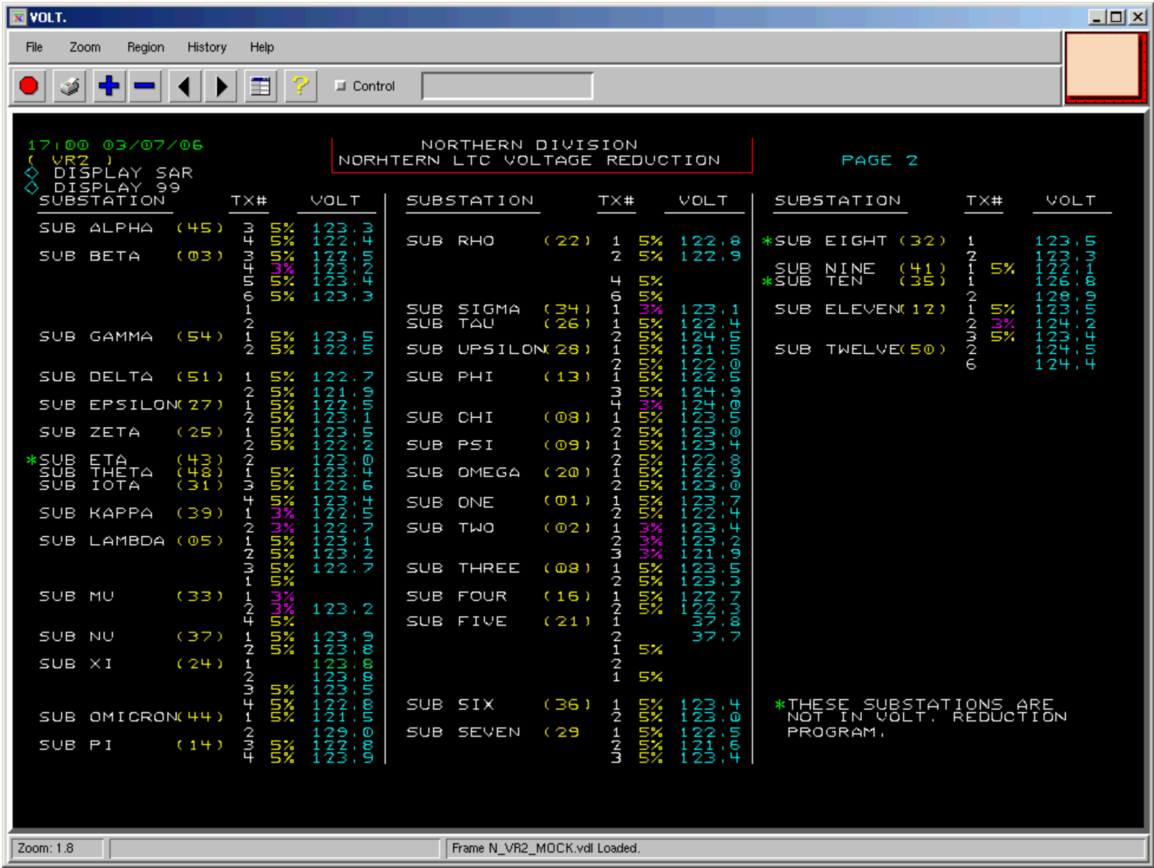


The next example screen shows another view of the individual circuits in the load-shed increments. The circuits that are part of increments 1 and 2 in the northwestern region are shown on this page along with their status and the substations in which they are located. The actual substation names have been replaced with aliases for security reasons. Also shown is the estimated load in each increment that is subject to being shed. These load estimates are based upon historical seasonal peaks.

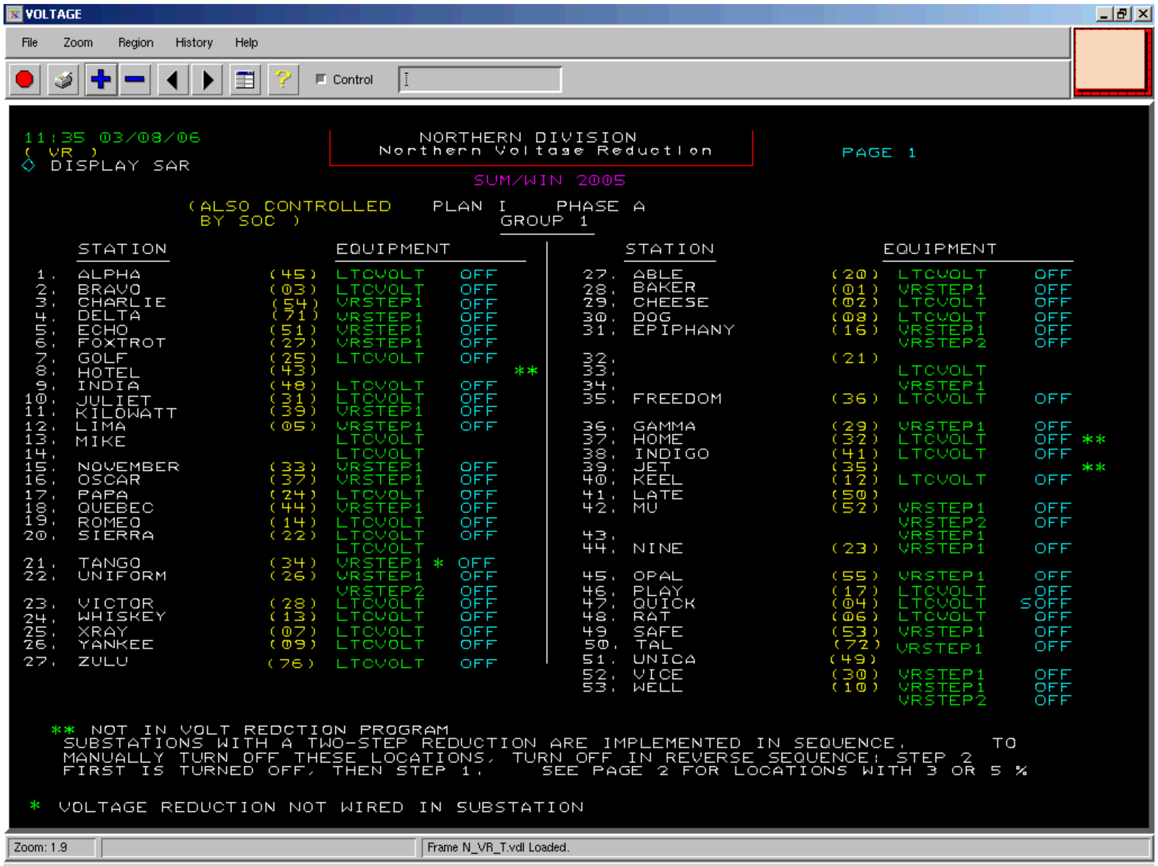


Prior to the development of this application, the previous practice for operator-controllable load-shed was to have the SOC operator (and the DOC operator at the direction of the SOC) use the SCADA systems to send individual circuit breaker trip and close commands to the various substations with circuits eligible for controlled load shedding as identified in the load curtailment plan. This was very time consuming, involved many different substation displays, and made load-shed rotation extremely difficult. Having the load-shed application enhances reliability and situational awareness by allowing quick response to a load-shed directive and overview monitoring of load-shed facility availability and expected response.

The following screen example shows all of the transformers at substations in Dominion's northern division that are controllable for voltage reduction. The actual substation names have been replaced with aliases for security reasons. This screen shows the reduction percentage (3 percent or 5 percent) that is available from each transformer along with the real-time voltage on the associated bus potential transformer secondary (the approximate single-phase voltage that the customers see).



The following screen example shows the status of the voltage reduction equipment at each substation in Dominion's northern division. The actual substation names have been replaced with aliases for security reasons. Equipment statuses preceded by an "S" such as is shown for substation "Quick" on the screen example means that a special order tag has been placed on the equipment. Special order tags usually indicate that some restriction has been placed on the operation of the equipment.



The in-house development of the software to facilitate load shedding and voltage reduction was based upon Dominion's operating needs for implementing its load curtailment plan. System operators provided critical input and feedback during the development. In addition to routine software maintenance of the application performed by the IT staff that supports the DMS, there is an annual, end-to-end load curtailment equipment test to verify correct operation.

Examples of Excellence

EOE-16
Reference — Section 3.6, System Reassessment and Re-posturing
Submitted by — VACAR Subregion of SERC

Description

Tool/Practice Name:	VACAR Guidelines For Addressing Situations Outside of Established Procedures
NERC Registration:	Reliability Coordinator, Transmission Operator, Balancing Authorities

Overview

The VACAR Subregion of SERC has developed documented guidelines to address events on the transmission system that are outside the scope of established operations. These guidelines, which are part of the *VACAR-South Reliability Coordinator Handbook*, are intended for use by the RC working in close coordination with the BAs (TOPs) within the reliability area. These guidelines contain several excellent examples of what to include in a procedure for reassessing and re-posturing the system following an event or events that leave the system in an insecure or unstudied state.

Particularly noteworthy is the section describing a generic approach to problem solving. This approach encompasses assessing the situation, diagnosing the problem, planning corrective actions, implementing the plans, and assessing after the fact the appropriateness of the actions taken. It also stresses communications and coordination among affected parties

The document follows in its entirety.

Procedure Name: Guidelines for Addressing Situations
Revision Date: 1/24/2005
Outside of Established Procedures

VACAR GUIDELINES FOR ADDRESSING SITUATIONS OUTSIDE OF ESTABLISHED PROCEDURES

Purpose

This guideline provides a framework for the reliability coordinator (RC) to use in addressing situations outside of established procedures. The RC shall rely heavily on system expertise that the Control Area (CA) operators have relative to the local area operation of their own systems with regard to problems that may result in the use of this procedure.

Conditions

Various types of conditions may become apparent to the RC that are not addressed in the current Emergency Operating Procedures (EOP). These may include:

• **Over voltage** conditions on a Member system: The RC shall coordinate with the CAs and other RCs to check the status of capacitor banks, voltage control devices, regulated volt-ampere reactive (VAr) reserves. If necessary, the RC will coordinate the removal of lightly loaded Extra High Voltage (EHV) facilities from service or insertion of reactive devices within the affected CA or neighboring CAs.

• **Under voltage** conditions on Member systems: The RC shall coordinate with the member CAs and other RCs to check the status of capacitor banks, voltage control devices, and regulated VAr reserves. If the condition still persists following the validation of the status of all VAr resources, the RC may need to review sales/wheeling schedules for their impact on voltage. It may also be necessary for the CA to consider redispatch of generation.

• **For first contingency transmission overloads** on the bulk transmission network that need to be relieved within a thirty **(30) minute** time frame, the appropriate procedures will be implemented to relieve the overloaded facility. This may include any available local operating procedure or NERC Transmission Loading Relief Procedure (TLRP).

• **For transmission overloads** on the bulk transmission network that need to be relieved immediately, methods listed below will be used to relieve the overloaded facility.

- Removing from service other transmission facilities in the area, which will off-load the overloaded facility.
- Removing from service the overloaded facility itself.
- Return to service any available outaged facilities that will help off-load the overloaded facility.
- Redispatch generation.
- Curtail energy and transmission schedules
- Curtail interruptible customers

• **Stability** of the interconnected network may become a concern of the RC and CA(s). If this is identified as a problem, the RC and the affected CA and other RCs should:

- Verify network topology
  - Determine if local conditions are contributing to the stability problem,
  - If local conditions are not a contributing factor, notify neighboring sub-regional and regional RCs

- Verify the status of Power System Stabilizers (PSSs) in the area.

Problems in other Reliability Coordinator's Security Areas

The problems discussed above (over- and under-voltage, contingency, and stability) may exist in other RC's Reliability Areas and resolution will require coordination between VACAR and these other areas. To the extent that VACAR CAs impact these external problems, the VACAR RC will work, in the manner described above, with those CAs and other RCs to rectify the situation.

Generic Approach to Problem Solving

Should all the above fail to correct problems on the bulk interconnected network under the responsibility of the VACAR RC or problems which the VACAR RC has been requested to help alleviate, the VACAR RC should attempt to solve the problem utilizing a generic approach to problem solving, which will continue to utilize contact with the affected CAs and other RCs. This approach involves five (5) steps. This diagnostic process can aid the RC and system operators in addressing problem situations in a systematic manner. The RC should rely heavily on system expertise that the CAs and other RCs have relative to the local area operation of their own systems with regard to problems that may result in the use of this procedure.

- **Assessment of Situation:** This involves assembling data that is available to the RC, gathering additional data from remote sites and/or systems, and evaluating the evidence. From the large amount of data available, the RC must focus on the data that is critical to the problem. Throughout the process, the RC should remain alert for new data and be prepared to integrate all evidence received. As part of the immediate assessment of the situation, the RC must decide the urgency of the problem and the need for decision or action.

- **Diagnosis of Cause of Problem:** This step involves formulating alternative interpretations of the event, gathering additional information as needed to support or refute the interpretations, and finally determining the most probable cause of the problem. The RC should retain an open mind in reviewing the evidence and examining different possible causes of the problem. Knowledge of previous incidents and of system/equipment history should be used in formulating explanations. A team brainstorming approach including RC and CA resources can be helpful in maintaining the openness at this point in the problem solving process. Once explanations have been formulated, additional information that would help select the explanation can be sought. At this point, the search for information is clearly focused and the questions should be closed rather than open-ended. With further evidence the RC should now be ready to select a working explanation to use in planning a corrective strategy. However, the RC should constantly monitor the system data that may necessitate a change in direction.

- **Planning Corrective Strategy:** When planning a corrective strategy, the RC should identify a workable solution, evaluate the potential consequences of the strategy, communicate the strategy, and plan for contingencies. The strategy should be one that responds to the cause of the problem as identified in the diagnosis. The selected strategy should meet two general guidelines. The strategy should respond to all the identified causes and minimize any potential adverse consequences. In many situations some trade-off of reliability versus economy is involved. In all cases, the RC should plan for contingencies both during and after implementation of the strategy. Once a strategy has been selected, all those involved in its implementation should be informed. All those involved in implementing the strategy and monitoring its effectiveness should be aware of the overall strategy and their role in it. If changes are made, they should also be clearly communicated to all those involved.

- **Implementation of Corrective Strategy:** Implementation of the strategy involves performing the required actions and monitoring the results. All steps of the strategy should be clearly communicated among the affected parties. Confirmation of the steps taken and corresponding results of this strategy should be provided to the RC by the CA(s). The RC should continuously remain alert for new data that may indicate the need for a shift in strategy.

- **After the Fact Analysis:** After the immediate problem has been resolved, the incident should be analyzed to determine whether appropriate actions were taken. After resolution, additional evidence may become available. Real time response to the event should be evaluated and appropriately documented.

Examples of Excellence

EOE-17

Reference — Section 5.1, Display Maintenance Tool
Submitted by — California Mexico Reliability Coordinator (CMRC)

Description

Tool/Practice Name:	Display Maintenance Tool Application
NERC Registration:	Reliability Coordinator

Overview

By using an equivalent display maintenance tool application, CMRC has taken a slightly different approach to ensure that its EMS displays are functioning properly (i.e., showing correct information, linked correctly) to maintain situational awareness for CMRC's operators.

All of CMRC's network application one-lines are derived from auto-generated simplified displays. Most external stations are left in the simplified form. Displays for internal stations are edited to include detailed switching and bus arrangement detail. Elements added to a display are automatically updated in the network model database using the display maintenance tool (through a visual display). This has prevented extended periods of downtimes for certain EMS failures.

Examples of Excellence

EOE-18

Reference — Section 5.2, Change Management Tools and Practices
Submitted by — PJM

Description

Tool/Practice Name: ChPro Change Management Tool

NERC Registration: Reliability Coordinator

Overview

RTBPTF notes that each entity has taken a slightly different approach to ensure that software modifications do not compromise the availability and integrity of critical real-time applications that support operator situational awareness. However, RTBPTF notes that PJM has a feature management system that resides only on their development environment. PJM also has a server identified as the source master server for that environment. Each code change that is made needs to be logged through the feature management system called "ChPro" on the development system. "ChPro" provides audit logging and version control capabilities. Once the code change is logged it can be moved to other environments for testing. Typically these changes are installed and tested on their process control test (PCT) environment, which receives real-time data from their production (PRD) environment to simulate results in the PRD environment. Once tested on the PCT environment, the feature must be logged in a change management system called REMEDY. These features need manager approval as well as operator notification and approval prior to being installed in the PRD environment unless the change is considered an emergency. Emergency changes can be installed immediately upon operator notification and approval to fix a problem. If the change is an emergency change, a REMEDY request must still be submitted for approval by a manager at a later time. Any change installed on the PRD environment is immediately re-tested to insure application integrity and availability. After the change is tested and approved on the PRD environment, it is moved to all other environments to insure synchronization of all systems. The PJM software maintenance tools and processes successfully comply with SAS 70 Type 2 audit standards.

Examples of Excellence

EOE-19
Reference — Section 5.3, Facilities Monitoring
Submitted by — American Electric Power (Central and Southwest)

Description

Tool/Practice Name:	Facilities Monitoring Application
NERC Registration:	Balancing Authority and Transmission Operator

Overview

Using equivalent facilities monitor applications, entities have taken slightly different approaches to ensure that critical equipment and facilities are functioning properly to maintain situational awareness for their operators. Central and Southwest (CSWS) interfaces its facilities monitoring application (called “Big Brother”) with its critical applications monitoring application. This interface provides CSWS with an extremely flexible tool for monitoring and notification (paging) for numerous aspects of it system.

Examples of Excellence

EOE-20

Reference — Section 5.4, Critical Applications Monitoring
Submitted by — Tennessee Valley Authority

Description

Tool/Practice Name:	Critical Applications Monitoring
NERC Registration:	Balancing Authority and Transmission Operator

Overview

Tennessee Valley Authority (TVA) uses a tool that monitors all critical and non-critical processes on their SCADA system. If a process fails, TVA's Network Operations Center can restart the process from a visual display. This has prevented extended downtimes during certain EMS failures.

Examples of Excellence

EOE-21
Reference — Section 5.4, Critical Applications Monitoring
Submitted by — International Transmission Company

Description

Tool/Practice Name:	Critical Applications Monitoring
NERC Registration:	Transmission Operator

Overview

International Transmission Company uses a tool that monitors the status of its state estimator and ICCP data applications. The tool generates text messages to a cell phone, which are automatically sent to an on-call operations engineer when the state estimator aborts and does not converge. When the data flow rate on the ICCP data links stalls, the tool sends text messages to a cell phone, which automatically goes to on-call IT support personnel and an on-call operations engineer.

Examples of Excellence

EOE-22
Reference — Section 5.4, Critical Applications Monitoring
Submitted by — American Transmission Company

Description

Tool/Practice Name:	Critical Applications Monitoring
NERC Registration:	Transmission Operator

Overview

American Transmission Company has created overview displays that not only show system performance but also EMS health checks. These overview displays allow the system operator to determine whether the EMS is operational and functioning properly. System operators are required to display these overview visuals and to notify the on-call EMS contact if a problem appears.

Examples of Excellence

EOE-23
Reference — Section 5.4, Critical Applications Monitoring
Submitted by — American Electric Power (Central and Southwest)

Description

Tool/Practice Name:	Critical Applications Monitoring
NERC Registration:	Transmission Operator

Overview

Central and Southwest (CSWS) interfaces its EMS Facilities Monitoring application (aptly called “Big Brother”) with its critical applications monitor. This interface is an extremely flexible tool for monitoring of and notification (paging) regarding numerous aspects of the CSWS system.

Examples of Excellence

EOE-24
Reference — Section 5.5, Trouble-Reporting Tool
Submitted by — Florida Power and Light

Description

Tool/Practice Name:	Trouble Report System
NERC Registration:	Transmission Operator and Balancing Authority

Overview

Florida Power and Light's (FPL) Trouble Report System (TRS) is a web-based application developed in house to facilitate logging, communication, and tracking of user problems with tools and systems maintained by the computer support group at FPL's System Control Center. Users are primarily operators. In addition to allowing entries of new trouble reports, the application performs administrative functions and can produce different query-based summary reports. The process flow and other functionalities are described below.

New Trouble Report Entry

Whenever a user encounters a problem with a tool or application, s/he can call computer support personnel or initiate a trouble report entry. Even if the user opts to call to report the problem, FPL considers it good practice to initiate a trouble report through TRS to ensure tracking. TRS also has an interface to FPL's e-mail system, so users can track trouble report status and eventual resolution. Trouble reports can be initiated by users or by support personnel that receive a call. When support personnel enter the report, they do so on behalf of the user reporting the problem. Once the user saves the entry, the trouble report status becomes PENDING.

Initial Evaluation

Support group personnel are assigned to periodically scan the TRS for reports with PENDING status and select the appropriate functional area to investigate and resolve each report. When the report is assigned, its status changes to ANALYZE, and an e-mail is automatically issued to the supervisor of the selected functional area notifying him/her of the new trouble report that has been assigned to his/her group.

If information provided by the user is insufficient for personnel to assign a report, the report status can be changed to MORE INFO, which automatically issues an e-mail to the user requesting more information. Once the user provides more information and saves the entry, the status returns to PENDING, and the process begins again.

Functional Area Process

The functional area supervisor, when notified by e-mail of a report, analyzes the problem. (The report can be accessed simply by clicking on the URL link provided in each e-mail issued by TRS.) The supervisor will then do one of the following:

- Assign the trouble report to appropriate personnel — This changes the status of the report to WORK ASSIGNED and generates an e-mail notifying both the staff member assigned to the report and the user that the report has been assigned. The supervisor determines the severity of the problem and assigns a priority to the report: high, medium, or low. The “Trouble Area” and “Application” fields of the report should also be filled in at this time. This information is useful for classifying problems in summary reports.
- Reassign the report to another functional area — The report status remains ANALYZE, and an e-mail is sent to the supervisor of the new functional area.
- Ask for more information regarding the problem — The supervisor can change the status of the report to MORE INFO, which generates an e-mail to the user requesting more information. Once the user provides more information and saves the entry, the status returns to ANALYZE, and an e-mail is issued to the functional area supervisor.

Trouble Resolution

The analyst assigned the trouble report reviews the severity of the problem and determines, based on workload, when to begin work on the problem. During the resolution stage, any of the following may occur:

- Problem is corrected — Once the analyst resolves the problem, s/he changes the report status to FIXED and describes the resolution. If the resolution requires code changes, the “Code Change Req” flag is selected, and modules that have been modified are specified in the resolution description. TRS automatically issues an e-mail to the user who reported the problem and to the functional area supervisor indicating that the problem has been fixed.
- No action could be taken to resolve the problem — This may be a result of an inability to duplicate the problem or determination that resolution of the problem would constitute a system enhancement, which requires that it go through a change management process. In this case, the analyst updates the status of the report to NO ACTION. TRS automatically issues an e-mail notifying the user who reported the problem and the functional area supervisor of the status change.
- Need more information from the user — The analyst can change the status of the report to MORE INFO. This generates an e-mail to the user requesting more information. Once the user provides more information and saves the entry, the status returns to WORK ASSIGNED, and an e-mail is sent to the analyst.

User Feedback

The user who initiated the report should verify that the problem has been corrected or agree that the problem is an enhancement that requires initiation of a change request. In both cases the user should update the status of the trouble report to CLOSED. If s/he disagrees with the resolution, a description of the disagreement is entered, and the status should be changed to NOT FIXED, which generates an e-mail back to the analyst.

Administrative Functions

TRS will e-mail weekly reports to each functional area supervisor listing all outstanding trouble reports assigned to their groups. These reports are copied to management. Outstanding trouble reports are those with a current status of ANALYZE, MORE INFO, WORK ASSIGNED, or NOT FIXED. TRS provides the following statistics on a per-trouble-report basis:

- Time elapsed from a report’s first entry to the system to its assignment to a functional area
- Time elapsed from assignment to a functional area to assignment to an analyst
- Time elapsed from assignment to an analyst to resolution
- Total time spent on a trouble report (from initial entry to completion)
- Total number of times that a trouble report was returned by user as not fixed

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
June 10–July 11, 2009

Now available at: http://www.nerc.com/filez/standards/Project2009-02_Real_Time_Tools.html

Standard Authorization Request (SAR) for Real-time Tools (Project 2009-02)

The Standards Committee has posted a proposed SAR for a 30-day comment period **until July 11, 2009**.

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net.

The status, background, and supporting documents for this project — including an off-line, unofficial copy of the questions listed in the comment form — are posted at the following site: http://www.nerc.com/filez/standards/Project2009-02_Real_Time_Tools.html

Project Background:

According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* dated April 2004, a principal cause of the August 14 blackout was a lack of situational awareness, due in part to inadequate reliability tools. Recommendation 22 of the report states, "Evaluate and adopt better real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate real-time tools and their usage within the industry. The Task Force produced a report, *Real-Time Tools Survey Analysis and Recommendations*, in March 2008 that included recommendations for the functionality, performance, and management of real-time tools: http://www.nerc.com/docs/oc/rtbptf/TOC_ExecSumm_Intro_2_1_08.pdf.

The SAR addresses selected recommendations in the RTBPTF Report as determined by the Real-time Best Practices Standards Study Group: Project 2009-02. The SAR proposes developing requirements for the functionality, performance, and management of real-time tools for reliability coordinators, transmission operators, and balancing authorities for use by their system operators in support of reliable system operations, with a focus on alarming, telemetry, and network analysis.

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.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (42 Responses)
Name (29 Responses)
Organization (29 Responses)
Group Name (13 Responses)
Question 1 (40 Responses)
Question 1 Comments (42 Responses)
Question 2 (38 Responses)
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Question 7 Comments (42 Responses)
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Question 8 Comments (42 Responses)
Question 9 (2 Responses)
Question 9 Comments (42 Responses)
Question 10 (0 Responses)
Question 10 Comments (42 Responses)

Individual
Jason Shaver
American Transmission Company
No
ATC believes that this should be addressed in the certification process, and if necessary a re-certification process. If that effort fails to achieve the overall goal of this SAR, (Minimum types of Real-time tools) then we would be more open to a standards develop project.
No
Please see our comment to question 1.
Yes
This approach should be incorporated into the certification/re-certification process.
Yes
Please see our comment to question 1.
No
If this SAR is continued then the team needs to provide more information about the proposed performance metrics. (i.e. Definition(s), Calculation(s), Exclusion(s) and Goal(s)) In addition, the team should gather and provide information that can support the establishment of a minimum performance level. Setting a performance level will require strong technical support.
A new definition will likely be needed if this project moves into a standards development phase;

otherwise the existing definition may be suitable. (The certification / re-certification may not need to define Real-time but only identify minimum tools required for certification.)
Certification Process
and re-certification process
Not aware of anything that applies.
Individual
Edward Stein
self
Yes
Yes
Yes
Yes
Yes
No
Wordsmithing the definition of real time is a huge waste of (real) time. Everyone knows that real time data is between two and five seconds old (maybe even longer) depending on the scan rate. There has been some type of sabotage reporting rule or requirement for over 30 years because it was the sexy and politically correct thing to do even though there was no way that a System Operator, with his office in the middle of a corn field, knew if the line trip was due to sabotage or not. Even when the troubleman arrived at the scene of the outage, he still may not be able to determine if the tower fell down because it was a sabotage event or a local farmer removing some of the tower's bracing in order to use the bracing to hold up his corn crib.
Yes
Although these GOP requirements should be part of the interconnection agreement between the Generator and the Transmission Provider, it may be more straight forward to have these requirements addressed in this SAR.
Reliability Standard
I am not sure what is meant by the certification process. I thought that the certification process was a one time deal. If the certification process is conducted annually, you may be able to not have this as a reliability standard. However if an entity loses their certification what happens to then and more important what happens to reliability.
There shouldn't be any.
Individual
Scott Vidler
Hydro One
Yes
From my travels and contacts I've witnessessed extreme variances in tool capability among control centres. A lack of standards has allowed companies to cut corners while others strive for excellence.
Yes
I agree if items such as wide area displays, identificaion of equipment outages (tagging, colours) which are crucial for visualization are being considered in other standards.
Yes
It is the end result that counts - how you get there will within reason be driven by the standards.
Yes
Network analysis is so broad that many functions can be included in this category i.e. dynamic

equipment ratings, short circuit analysis, breaker duty cyclee etc that this SAR can be as broad as required.
No
One thing not indicated under performance metrics is actual performance i.e. alarm bursts, state estimator solve time or frequency of run, contingency analysis completeion time. If a SE only runs every 30min and takes 10min to solve how effective is it?
No
It is a good discussion point but it is splitting hairs a bit. Real Time is what you see now whether it took 5 minutes to get all the information or SE to solve. If the concept is to define how long it takes to refresh the data i.e. a 2 second refresh then that will drive home performance.
Yes
A lack of situation awarness, alarms and telemetry that ends up with a generator(s) contingency will have an impact on the reliability of an area so it is as important.
Reliability Standard
Group
WECC Reliability Coordination
Yes
Our only concern is that the standard may outpace the available technology. Also, only tools that are applicable to all interconnections should be inlcuded in the standard.
Yes
It appears that there may be a dollar and resource impact associated with the new and revised standards, so a phased approach may be required.
Yes
Although it appears that in the survey results that some items are specifically mandated.
No
The survey results focus on additional items not listed above and do include data requirements such as day ahead study data requirments, path limts requirement and special protection schemes monitoring applicability.
Yes
The word quality needs to be clearly defined and measurable.
Yes
Yes
Reliability Standard
none at this time
We have an overall concern that an implementation process needs to be coordinated to minimize the impact to organizations that do not have the current resources or dollars to immediately implement the proposed changes. Also, it appears the SAR requires specific procedures rather than guidelines for event mitigtion, which does not provide the operator or RC leaway to assess all the variabiles in the interconnection. The role and responsibility for each requirement also needs to be clearly defined.
Group
NERC RTOSDT
Yes
The RTOSDT technically takes no position on the reliability need for requirements that state which specific tools are required, as we believe this to be the answer to the "how" question as opposed to the "what" question which is the nature of a true reliability requirement.
Yes

Again, the RTOSDT takes no position on the scope.
Yes
The RTOSDT agrees, however, it seems unlikely to be achievable in this case. Discussions surrounding analytical capabilities seemingly always devolve to specific tools.
Yes
The RTOSDT takes no position on this issue.
Yes
The RTOSDT agrees that a set of metrics is useful. Further, the RTOSDT believes that NERC must grapple with the concept that no information system is perfect. That is, requirements that involve information systems should only specify a "designed" level of performance, not the actual level of performance. It is nonproductive to investigate and fine an entity for failing to have two scans of an RTU, for example. The intent of a requirement related to information systems should always allow for reasonable failover times if redundancy is required and should allow for something less than 6 sigma performance, especially considering that communication networks outside of the control of reliability entities may have at best 2 sigma performance.
Yes
The RTOSDT takes no position on this at this time. However, unintended consequences may occur. This needs a lot more explanation to the industry.
Yes
The RTOSDT can see no reason to preclude the adding of the GOP at the SDT phase of the project.
Certification Process
Discussions at the RTOSDT have generally yielded consensus that these are basically one-time requirements, at certification time, and which specify the "designed-in" level of performance, while not focusing on the actual performance in absolute terms. That is, any actual performance requirements should be statistically sound. For example, it is patently absurd to believe that BAL-005-0.1b R8, which requires ACE calculation at least every 6 seconds, is actually possible with real computer systems. On a design basis, this means that a hot backup with failover within a couple of minutes is required. On an actual performance basis, this is far better than the up-time required of space shuttle computers. Something like 2 sigma or 3 sigma performance for actual results is quite possibly all that is needed for the uptime for these tools.
N/A
FERC Order 693, paragraphs 1659 to 1665, mandate the addition of a requirement in the TOP standards for a minimum set of analytical tools for carrying out TOP reliability functions and that relay closing phase angle data be presented to operations staff: Tools and capabilities are a very broad, yet specialized topic that demands industry input of a more focused nature than that possible in current Project 2007-03 (Real-time Operations) upon which the RTOSDT is working. The RTOSDT believes that the Subject Matter Experts (SMEs) that will be gathered in support of this SAR will be better qualified to address this issue, and to elicit industry input, than the operational SMEs supporting Project 2007-03. The RTOSDT is basing its response to FERC for this matter on this item being vetted and supported by Project 2009-02 as appropriate.
Individual
Alice Murdock
Xcel Energy
No
Several standards (IRO-002, TOP-006, TOP-008) already address the issues identified in this SAR. Rather than develop a new standard, we recommend evaluate or incorporate into an existing project for these standards.
No
There is concern that the SAR may be expecting research and development of tools. This is not an appropriate use of a SAR.
Yes
No
It is not clear as to how far reaching standards for these functions would be. For example, we would not be in support of anything that would infer the need to install duplicate instruments to provide information to a Reliability Coordinator (as in most cases this data is acquired by the TOP and BA

and then passed to the RC).
No
Any requirements created to impose metrics should allow for exceptions for extended outages of equipment for uncontrollable reasons. As written in the recommendation report, an outage on a real time tool for as short as a few hours could create significant non-compliance events, while not having any impact to the reliability of the system.
No
Use of industry groups such as the Transmission Owners and Operators Forum, and EPRI should be considered in development of best practices and tools for use in real time operations.
Group
Southern Company
Yes
In the absense of a certification process with re-certification, new standards should be established only if the same end can't be reached by revising existing standards. The RTBPTF's report gave several examples where real-time tools were mentioned but not well defined in existing standards. The SAR team should begin developing new standards only after they have determined that the same results can't be obtained by revising existing standards.
Yes
This SAR covers the concerns spelled out in the Real-time Tools Survey Analysis and Recommendations report.
Yes
Yes
No
Availability and quality would be acceptable measureable metrics. Change management, maintenance coordination, and failure notification are processes and would have to be measured through documentation.
No
If a NERC Glossary term used in other standards is re-defined than the meaning of those standards has been changed without revision. The IRO standards use real-time as a description of a planning horizon or describing the data being used. Personnel operating the bulk power system understand that real-time data can be several seconds to several minutes old. The team may want to define the limits of near real-time data.
Yes
Certification Process
These requirements need to be included in an entity's certification process that includes periodic re-certification. This would require entities to certify that they have the tools needed to perform these functions and mechanisms in place to continue to perform the functions.
Individual
John Brockhan
CenterPoint Energy
No
CenterPoint Energy does not agree there is a reliability-related need for these proposed standards. The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations reports on page 19 First Energy (FE) had state estimation and contingency analysis tools. The "…tools were not used to assess system conditions, violating NERC Operating

Policy 5, Section C, Requirement 3, and Policy 4, Section A, Requirement 5. FE personnel did not ensure that their Real-Time Contingency Analysis (RTCA) was a functional and effective EMS application as required by NERC Policy 2, Section A, Requirement 1." CenterPoint Energy agrees that real-time monitoring and network analysis tools are necessary however, CenterPoint Energy believes the appropriate forum to evaluate an entities tools and their use would be during the certification process for a RC, BA, or TOP. Items such as functionality, performance, and management of the available tools as well as availability and quality of the entity's tools and how the entity uses the tools in their operation could be measured as well.
No
See response to Q1.
No
See response to Q1.
No
See response to Q1.
No
See response to Q1.
No
The current definition is sufficient. Any inherent time delay involved in the acquisition and dissemination of data to system operation personnel is understood. While that delay should be minimized, there are technical and financial limits to what can be done.
Certification Process
See response to Q1.
Individual
James H. Sorrels, Jr.
American Electric Power
No
AEP fully supports the need for entities to have an adequate tool set to operate in a reliable manner. However, it is AEP's belief that that reliability issues that this SAR intends to address are not resulting from a void in the reliability standards, but instead in the current certification processes. For example, some RTOs require that there are qualified systems in place prior to operating, while others require that individuals be certified. We would support that both elements are necessary, that is the right tool set verified and individuals having NERC certification, and that this occur in advance. Using the NERC certification process of functional entities to ensure that the right tool set is in place and operating correctly is preferable to allowing, by administrative registration alone, to begin operating and then, afterwards, try to invoke standards to address operating issues that could have been avoided up-front. The certification process will need to also be modified beyond a single verification to a periodic process to ensure tools remain in place and are operating as expected.
No
AEP believes that these actions are largely covered in the existing standards, including those shown below (Table 1) in the related SAR functions format. Repetition of requirements across multiple standards may create ambiguity if alternative requirements or methods are defined from one to the other. It also establishes the possibility of compounding violations for a single infraction. To the extent that new requirements are needed to address operational gaps, these could be made in the next revision of the applicable existing standards, which is to be done on a periodic basis. TABLE I - Existing NERC Reliability Standards addressing Alarming, Telemetry, Network Analysis, Related Performance Metrics (Availability and Quality), and Processes and Procedures supporting Real-Time Tools (Change Mgt., Maintenance Coordination, and Failure Notification) : Alarming COM-001-1.1, does have some language related to the alarming of vital telecommunications facilities for voice and data. TOP-006-2 stress the importance of monitoring equipment to be used to 'alarm' or bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action. IRO-002-2, gives direction on the alarming management and awareness systems that need to be in place for the RC. Telemetry BAL-001-0,

dealing with the ACE equation along with Control Performance Standards (CPS1 and CPS2) BAL-004-0, addressing Time Error Corrections BAL-005-0.1b, focuses on the telemetry components necessary for calculating the ACE equation BAL-006-1.1, tasks the Balancing Authorities to calculate and record hourly Inadvertent Interchange IRO-004-1, details the information that needs to be sent to the RC for reliability studies to be performed IRO-005-3, breaks down most of the parameters that a RC would need to receive for monitoring the BES TOP-002-2, highlights that changes in transmission facility status, along with ratings should be monitored and conveyed to the RC and BA TOP-005-2 is the Operational Reliability Information standard that lays out all of the data that needs to be updated at least every ten minutes TOP-006-2 is another standard focused on monitoring system conditions. VAR-001-1 also is offering details on what data should be pipelined back to the operating control centers from the BES. Network Analysis IRO-004-1, discusses the ability for the RC, TO, and BA to conduct next-day reliability analyses to ensure that the BES can be operated reliably. TOP-002-2, looks at the performance of current-day, next-day, and studies operational studies in conjunction with neighboring BA(s) and TO(s). TOP-002-2, also address the thermal and voltage contingency analysis that needs to be performed. IRO-002-2, details the analysis that needs to take place via state estimation and other visualization tools. Performance Metrics for Availability and Quality Availability Availability BAL-005-0.1b, R8 looks at SCADA availability to gather data and calculate ACE. This requirement also address the availability of Frequency Metering equipment (99.95%). COM-001-1.1, stresses the diversity and redundancy of communication paths for the available exchange of Interconnection and operating information, internally and externally to AEP. EOP-008-0, emphasizes the development of a plan to ensure the monitoring and control of transmission, distribution and generation assets even with the loss of the Control Center. Quality BAL-005-0.1b, R17 breaks down the accuracy of the metering devices for time error and frequency measurements BAL-006-1.1, requires adjacent balancing authorities to have common megawatt-hour meters at the interconnection point. IRO-005-3, discusses the importance of operating to the most limiting element if there is a discrepancy between various entities monitoring the same facilities. TOP-006-2 generically states that sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions. Processes and Procedures supporting Real-Time Tools: Change Mgt., Maintenance Coordination, and Failure Notification Change Management FAC-009-1, obligates the communication to RC(s), PA(s), TP(s), and TO(s) for new facility ratings on the Bulk Electric System. TOP-002-2, implies that there should be a facility change notification system in place for neighboring entities to use uniform line identifiers when referring to interconnected facilities. BAL-004-0, addressing Time Error Corrections Maintenance Coordination FAC-009-1, it is implied that these changes will be applied to the real time computer model with alterations to facility ratings on the Bulk Electric System. TOP-002-2, talks about each BA and TO maintaining accurate computer models for analyzing and planning system operations. Failure Notification IRO-005-3, highlights the responsibility to identify significant issues with ACE that can attribute to other errors, such as frequency error and Time error.
No
While we do agree that "what," not "how," is the correct approach to describe the required real time tools, we believe it should be established in the certification process as described in item #1 above. While it is easy to say we will confine ourselves to "what," it's difficult to prevent establishing criteria that inadvertently leads to a particular "how." Should "how" occur, it limits opportunities for improvements and innovation, and could hamper better results. AEP agrees with this approach of describing "what" needs to be done, as opposed to "how" to do it, as this preferred approach encourages new technology development in achieving the intent of the standard.
No
As described in item #2 above, we believe that these areas of focus are already covered in the existing standards (Table I). NERC is actively involved in consolidating standards in the revision process as witnessed in Project 2006-03. Creating new standards unnecessarily would be counter productive to this trend.
No
AEP believes that these actions are largely covered in the existing standards, including those shown previously (Table 1) in the related SAR functions format. Repetition of requirements across multiple standards may create ambiguity if alternative requirements or methods are defined from one to the other. It also establishes the possibility of compounding violations for a single infraction. To the extent that new requirements are needed to address operational gaps, these could be made in the next revision of the applicable existing standards. In any case, if this SAR proceeds, it must be

limited to the “what” issues of “availability” and “quality”, and NOT on the “How” issues of "change management", "maintenance coordination", and "failure notification."
No
Real-time is a precisely NERC defined term. In addition the Real-time term is highly integrated in the existing standards. Re-defining the term could have a significant impact on a wide-range of existing standards.
No
AEP does not believe that it is necessary to include the GOP as an applicable function for this SAR, as data requirements are specified in existing standards. As mentioned in Item #1, using the NERC certification process of functional entities to ensure that the right tool set is in place and operating correctly is preferable to allowing, by administrative registration alone, to begin operating and then, afterwards, try to invoke standards to address operating issues that could have been avoided up-front.
Certification Process
It is AEP’s belief that that reliability issues that this SAR intends to address are not resulting from a void in the reliability standards, but instead in the current NERC functional entities certification processes. A participant should have, upfront, at least the tool set to operate at an adequate level. The certification process is the appropriate forum for checking the systems. Furthermore, the NERC functional entities certification process could provide periodic checks to maintain certification by ensuring that the tool set remains in place. The upfront verification becomes a must as one considers that potentially thousands of non-traditional generation facilities may be interconnected in the near term.
There should not be differences in the required tool sets, based on regional differences, if the requirements stay at the “what” level.
No further comments at this time.
Individual
Alan Gale
Cityof Tallahassee (TAL)1
No
While it should be mandatory for the RC’s to have these reliability tools, it is a “best practice” for many of the TO’s. For many other TO’s it would be overkill to have to establish these programs for a relatively small area that is fed from only a couple of lines. How does the applicability change for the size of the organization? Standards should be the MINIMUM needed to operate reliably, not a culmination of the industries “best practices”.
No
This should be targeted to the RC’s initially. Let’s get it up and running for them before we make it mandatory for the TO’s and BA’s. Many TO’s and BA’s will pursue them during the interim because they will know it is coming and can begin the long trek to get there.
No
While I can appreciate NERC trying to avoid mentioning specific brand names, there is no point in not saying you have to have a Contingency Analysis Program if that is what you want us to have. The continued interpretation of what NERC wants becomes a guessing game and we don’t find out that we guessed wrong until we are audited.
No
See response to question 1. Network Analysis does not need to be a requirement for smaller TO’s. Until we can provide some way of avoiding the large expense without a measurable increase in reliability, we should not be pushing this function onto the TO. The TO’s SHOULD be responsible for providing the data needed to the RC so his model works properly.
No
The SAR identifies 2 performance metrics, Availability and Quality. The remaining three functions are not metrics; they will be requirements to ensure the entities have them. The use of metrics for enforcement will become contentious. If I say I am sending data to the RC over my data link, but he says he is not getting it, who gets charged with the non-availability or reduced quality? If the problem is with a third party communication (Sprint, AT&T, etc) why should I get penalized for the “network” failure? There are too many things beyond the control of the entity to make it a “mandatory and enforceable” metric.

Yes
Yes
Generator data is an important set of data for real time modeling.
While I still disagree with a need for it to be a standard, IF it is moved to the Certification process, how will you monitor it on an ongoing basis? How will you ensure the currently registered entities have the tools?
- I must reiterate that a fully functional Network Analysis tool (Contingency Analysis) is a "Best Practice" and not a requirement for many TO's and BA's. I know of a case where the TO is not allowed to vote on Standard development because they do not own enough miles of transmission lines, but they would have to have a CA program by this SAR. The following comments are directly related to the Real-Time Tools Survey Analysis and Recommendations (Final Report) but do apply to the SAR. - Too wide of a "wide area view" may be detrimental to many TO/BA's also. If the RC is watching over the entire RC area, and the TO/BA is watching over a smaller portion with a large portion equivalized, and the RC's model goes down because of bad telemetry in another part of the RC area, the TO/BA's model may still be functional because it is not reliant upon the bad data for proper operation. - On page 27 of the Executive Summary, the RTBPTF identifies the need to address the definition of the Bulk Electric System. This should be done before any additional standards requiring the use of the definition are allowed to proceed. There is still not a good understanding of what it needs to be to ensure that it is reliable. Lets get this hurdle crossed before we make more references to it. - On page 17, Situational Awareness Practices: The first sentence "The task force concludes that documented conservative operations practices are a key element of situational awareness practices and thus includes conservative operations plans in its recommendations." This recommendation appears contrary to the desires of FERC to operate closer to the edge to allow maximum trade to occur based on the ATC standards undergoing revision/review. We should not have competing standards. - On page 25, Awareness of Load-Shed Capability: This "awareness" does no good if the operator does not pull the trigger. THIS is the major cause of the August 14, 2003 blackout and a recurrent theme of recent blackouts. The "word on the street" (from Compliance) is that if you have to shed load (an event), you will be investigated for compliance violations because you must have done something wrong to get to that condition. What message is that sending to the operators? - On page 29, Issue #6: Adequate Funding for Staffing for Real-Time Tools and Support Should be Ensured. This area could not be analyzed by the RTBPTF. However, it did not preclude them from making numerous recommendations to enact the Real-Time tools. I do not like creating standards or requirements without any idea of how it will financially impact entities. This WILL cost a significant amount of money to enact. While many entities (as evidenced by the participation in the survey") are already engaged in pursuing these standards, or want to, the financial burden created by making it mandatory and enforceable will have deleterious effect on reliability. The money is going to come from somewhere. Be it from rate increases or diversion of funds from other projects, delaying the construction needed to fix what is going to be shown on the CA program. The managers of the Reliability Entities are fully aware of the importance of supporting NERC Standards.
Group
PacifiCorp
Yes
Yes
Yes
Yes
Yes
Yes

Individual
Rao Somayajula
ReliabilityFirst Corporation
Yes
Yes
Yes
Yes
Yes
No
I do not think a new defintion is needed.
Yes
Certification Process
Individual
Kasia Mihalchuk
Manitoba Hydro
While this project has value, it should fall very low on the list of priorities. Other standards with greater risk to the reliability of the BES should be reviewed and revised before starting any new project.
See comment for Question 1.
Yes
Although the SAR does not intend to indicate "how to" perform the specific tasks/requirements, it may be useful to identify tools in a separate document that could be used to achieve the specific task without directing the use of a specific one.
Yes
Yes
Manitoba Hydro agrees that this is the correct set of metrics; however the definition and measures defined in the Standard will have to be very specific and defendable in terms of improving reliability.
Yes
Present or current time seem to mean the same. Suggested definition: The actual time at which an event occurs.
Yes
Reliability Standard
Group
Electric Market Policy

Yes
Yes
Yes
Yes
Yes
No
Most Transmission Operators (TOP) and Reliability Coordinators (RC) typically operate out of one control facility with information that expands beyond that provided by facilities under their direct control. There are protocols for coordinating operations of multiple facilities operated by different entities. Most Generator Operators (GOP) operate out a control room that contains information ONLY on facilities directly under that GOP's control. They are no protocols for coordinated operation of generating facilities. GOPs are to follow directives of the TOP and RC. Also, the federal/state codes/standards of conduct may prohibit dissemination of certain information between the RC/TOP and GOP entities. We strongly believe that placing new compliance requirements in this SAR on all generators is beyond the scope of what GOPs should be functionally doing in almost all generation locations on the bulk electric system and hence advancement of this standard with the inclusion in GOP applicability will actually create unnecessary complexity in operating the bulk electric system.
Certification Process
Individual
Greg Rowland
Duke Energy
Yes
However we are very concerned that the action to revise existing standards or develop new standards could be overly prescriptive. The requirements should remain at a high level, and focus on the "what", as opposed to the "how". The Introduction to the "Real-Time Tools Survey Analysis and Recommendations Final Report" contains 40 recommendations related to new or revised reliability standards; and we believe that many of these recommendations are too prescriptive to be placed in a reliability standard. This SAR should not become a project to implement all 40 of those recommendations. Additionally, we believe that many of these items more properly belong in an entity certification process and not in a Standard. The certification process should address core functionality tools. Standards should be used to address the operational application of these tools. See response to question #8.
No
We believe that the scope is too large to be manageable, and should be broken up into multiple projects.
Yes
See our comment to question #1 above. We are concerned that if requirements are overly prescriptive, they are describing "how" instead of "what".
Yes
No
These are good metrics, but they don't belong in a reliability standard. Performance metrics should be implemented and enforced as part of the certification process.
Yes

Yes
Certification Process
We believe that the high level requirements for functionality should be in the reliability standards, and that the certification process should contain performance metrics and procedures related to change management, maintenance coordination and failure notification. See response to question #1.
None
The drafting team should be very careful not to replicate requirements in multiple standards. For example TOP-008-1 Requirement R4 currently states: "The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation."
Individual
Jianmei Chai
Consumers Energy Company
Yes
Yes
Yes
Yes
Yes
Yes
The existing definition is not useful.
Yes
Reliability Standard
If these requirements would reside in a certification process, they would be scrutinized only once – during the certification process, and there would be no measurability of their ongoing presence, particularly with the demise of the Readiness Evaluation Program.
Individual
Darryl Curtis
Oncor Electric Delivery
Yes
Yes
Yes
Yes
Smaller entities operating within the bulk electric system may bear a higher burden than larger ones. The benefits of providing real-time network analysis for these smaller entities may be far less than the costs.
No
"Quality" should not be included. "Quality" is fundamentally subjective and cannot be measured
Yes

There will be an inherent delay in the processing of applications, processing of data and the identification of contingency measures related to real time analysis for as much as 15 minutes. On the other hand, typical telemetry updates of data to the user display are around 2-4 seconds.
No
Generator Operators provide alarming and telemetry for their own facilities and only a small amount of this data is typically available to assist in determining the security of the bulk power system. In addition, Generator Operators do not normally perform network analysis.
Individual
Scott Nied
Con Edison System Operation
Yes
Yes
Yes
Yes
Yes
No
Changing the definition would be confusing. Adding a new term or making people become familair with using the "real time" term and another term such as "future time" would seem to be logical also.
Yes
Reliability Standard
Reliability Standard. Not familiar with the Certication Process.
No comment.
No further comments.
Individual
Edward Davis
Entergy Services
No
Entergy supports the SERC OC comments.
Yes
Entergy supports the SERC OC comments.
Yes
Entergy supports the SERC OC comments.
Yes
No
Entergy supports the SERC OC comments.
No
Entergy supports the SERC OC comments.
No
Entergy supports the SERC OC comments.
Certification Process
Entergy supports the SERC OC comments.

Entergy supports the SERC OC comments.
Individual
Chris Scanlon
Exelon; ComEd, PECO and Exelon Generation
Yes
Yes
Yes
Agree that it is very important that a standard or certification process for validating Real Time Tools does not direct the applicable entities to use specific tools. Exelon endorses the "what", not the "how" approach as emphasized in the SAR.
Yes
Exelon suggests historical data (storage and retrieval) should also be considered as an appropriate function. Also, while these may be the right functions for Real Time Tools, a total systems approach should be emphasized as opposed to focusing on "silos" of information and functions, RTU data, hardware, software etc.
No
Exelon agrees performance metrics are important but we seek clarification concerning how quality, maintenance coordination, failure notification and especially change management are to be measured.
No
Exelon does not endorse a re-definition of Real-time.
No
Exelon sees no value in including the Generator Operator in the standard applicability. Data exchange and communication requirements are covered in other standards such as the COM and IRO standards. Additionally, RTO's, BA's and Transmission Owners and Operators typically specify in Interconnection Guidelines, Operating or Reliability Agreements and Manuals, what data must be shared between the Reliability Entities and the Generator Operators so as to support Real-time operational analysis.
Certification Process
Exelon believes the Certification Process as specified in the ROP, Organization Registration and Certification Manual, Appendix 5, would be the best way to verify that entities performing the reliability functions are adequately equipped to do so.
Not aware of the need for either.
Exelon appreciates the opportunity to comment on this SAR and commends the Real-Time Tools Best Practices Task Force for the work done to produce the Real-Time Tools Survey Analysis and Recommendations Final Report.
Individual
Kirit Shah
Ameren
Yes
Yes
Yes
This is the correct approach. Tools will change over time. Defining the “what” should be the focus. Leave the technical “how” to those developing solutions.
No
The SAR should include all aspects of the “Reliability Toolbox” as defined in the RTBPTF report.
Yes

Yes
Clarification of this term could be beneficial. “Real Time” can indicate significantly different time periods depending on the point of view. With the advent of new technologies such as phasor measurement units with a much higher sample rate, real time takes a very different meaning as compared to the traditional “seconds” based sample rates utilized in most current EMS/SCADA systems.
No
It states that there would be a focus on Alarming to alert on events and conditions affecting the state of the BES, Telemetry to provide status and analog values in real time (status of what?), and Network Analysis for simulating impact of what-if events. For Alarming, what action would a GOP take in response to an alarm, that would be independent of what GOP would be directed to do by TO or BA or RC? GOP is already subject to plenty of other NERC Reliability Standards that state that the GOP has to do what the BA/TO/RC tell him/her to do in order to preserve the BES integrity. For Telemetry, regarding status (if assume of Transmission Components) inreal-time operation, doesn’t that violate FERC Code of Conduct, since GOP is not supposed to know about Transmission information that may give him/her an advantage in the market? And as for Network Analysis, that has nothing to do with a GOP.
Whether the eventual approach is determined to be new or updated Reliability Standards or changes to the Certification Process the decision should be left up to the SAR drafting team.
No comments
No comments.
Individual
Brent Ingebrigtson
E.On U.S.
No
See comments for Question 8
Certification Process
Certified entities have been determined as capable of meeting the all applicable requirements. A new standard setting forth requirements for the tools employed by registered entities to meet existing requirements is redundant. Moreover, having NERC establish either functional or technical specifications for real-time systems will stifle innovation and unnecessarily lead many entities, who are currently meeting existing requirements, to invest resources in altering and not necessarily improving their existing real-time tools. It is better to leave the development of functional and technical specifications of rapidly changing technology to buyers and responding vendors. A failure on the part of registered entities to employ adequate real-time systems will in all likelihood lead to non-compliance with one or more existing requirements. It is nonsensical to describe a system that enables its owner/operator to meet BES reliability requirements as in any way insufficient.
Individual
Thamas J Bradish
RRI Energy
No
For the RC, TOP and BA "Yes" in some fashion but the SAR should not be applicable to a GOP. The GOP is not a system operator at the same level as a RC, TOP and BA. We do not have the information on the real time status of the BES. We do not know transformer loadings (other than our GSU), transmission line loadings, generator status (other than our own) and details of demand (local load and projected load). GOP's by statute are prohibited from knowing this information. A standard is not needed to mandate that we have real time tools. The GOP's EMS has the necessary

tools for the GOP to comply with the direction given them by the RC, TOP and BA. The GOP is required by the IA and market rules to follow the direction of the RC, TOP and BA. GOP is included as a System Operator but we believe that the definition should be modified. We plan to submit a SAR to request this change.
No
See comments from Question 1. This SAR should not include GOP in the applicability section.
Yes
Provided that the lack of the how will not cause an issue during an audit.
No
The SAR's focus on "alarming, telemetry and network analysis" I believe supports dropping GOP from the applicability. Our EMS contains the alarms and telemetry needed to comply with standards and market rules. What level of network analysis does the SAR contemplate a GOP performing? Further, if a GOP feels that it needs to have unit AVR mode telemetry to insure compliance to VAR-002 then the GOP will add that alarm to its EMS. An additional standard requirement is not needed for the GOP to have the necessary real time tools to support ALR of the BES.
No
I was unable from the SAR to understand why their was a need to redefine Real-time.
No
See previous comments.
Certification Process
Group
Northeast Power Coordinating Council
Yes
No
The scope of the SAR is too "invasive" to operations. The SAR should address the "output" requirements for the hardware and software-- operators must be provided with the information "results" they need to know to determine how the system is behaving real time, and also for possible system configurations (e.g. contingency analysis). Even though in the Brief Description section of the SAR it states "The intent is to describe 'what' needs to be done but not 'how' to do it." the performance and management of tools falls into the 'how' category. While NPCC suports the material in the RTBPTF Real-time Tools Survey Analysis and Recommendations report, the Standard should be limited to stating the reliability objectives of the Real-time Tools, leaving to each Registered Entity that must comply with the Standard the decision on how they are going to meet these objectives.
No
NPCC agrees that the SAR needs to emphasize the "what" that needs to be done to ensure the reliable and effective functionality, performance, and management of Real-time tools, not the "how" to do it. General categories of types of tools, such as state estimators, contingency analysis programs, etc. can be mentioned. How the results or outputs from those tools are generated, or the management of those tools outside the operating floor, are outside the scope of a standard. The results and of those tools and how they are used (and ease of use), are the most important issues.
No
NPCC agrees that the functions stated are correct, but not all inclusive. The SAR needs to clarify that all of the functions contained in the Real Time Tools Report are not being addressed at this time due to the expansiveness of the RTBPTF report. There should be a fourth required functionality identified as Control. Control would include the application of and methods to ensure control capability is maintained at a control center and remote substations.
No
The statement in Question 5 should be worded "The SAR details the need for performance metrics for alarming, telemetry, and network analysis functionalities, with the considerations of availability,

quality, change management, maintenance coordination, and failure notification." What is meant by the term "change management"?
Yes
NPCC agrees that the current definition that exists in the NERC Glossary of Terms where Real-Time is defined as "Present time as opposed to future time" is inadequate and needs to be redefined. Suggested rewording is: Real-time: 1. Existing or presently occurring. 2. In an information gathering or analysis environment, real time data and a time window allowed for its processing.
Yes
Reliability Standard
From the NERC Reliability Standards Development Procedure, ""Reliability Standard" means a requirement to provide for reliable operation of the bulk power system…". The ideas proposed in this SAR meet that definition, and belong in a reliability standard. NPCC believes that the certification of a function is only a snapshot in time. With technology continuously changing, there needs to be a process that will continuously capture these changes. NPCC is of the opinion that the NERC Standards are living documents and are the best mechanism available to the industry for capturing these changes by the continuous updating of the standard's requirements included within.
It is to too early in the process to identify whether there will be a need for a regional variance or business practice to consider with this SAR. NPCC believes that it is premature to either determine or conclude that an impact will exist in the future.
NPCC believes that this SAR serves as only a beginning for addressing Real Time Tools and should not be construed as all encompassing. What is the intention for addressing the input devices for these tools (i.e.--current transformers, potential devices, transducers)?
Group
Public Service Enterprise Group Companies
Yes
PSEG agrees that these items require a standard. However, creating a new standard for telemetry or other items may duplicate or conflict with what is in standards COM-001 & COM-002. The scope of this SAR should be expanded to include potential revisions to COM-001 and COM-002 to ensure that all three standards are complementary and consistent.
No
The scope of this SAR should be expanded to include potential revisions to COM-001 and COM-002 to ensure that all three standards are non-duplicative, complementary and consistent.
Yes
The SAR should be limited to the "what" and not include the "how." There are multiple equally effective ways of accomplishing the "how" and the decision as to which to use should be left to the impacted registered entities.
No
If the scope of this SAR is expanded to include potential revisions to COM-001 and COM-002 to ensure that all three standards are non-duplicative, complementary and consistent, then PSEG concurs that alarming, telemetry and network analysis are the right set of functions.
Yes
No
If "real-time" is redefined in the NERC glossary, it will be necessary to analyze the impact of this definitional change in each of the over 100 usages of this term throughout the full body of standards. If there is a particular concern about the speed/accuracy of "real-time" for this standard, then the specific requirement should be specified in this standard and not as a general definitional change.
No
Generator Operators do not fit within the scope of this standard. They do not have direct involvement in the matters covered by this SAR. Any necessary GOP actions or requirements would be covered in the interconnection or operating agreements between generators and the applicable entities.
Reliability Standard

While PSEG is not aware of the specific need for a regional variance or business practice, the SAR should specify that the drafting team should consider and give deference to the long-standing requirements of RTOs and ISOs (as RC, BA, and TOP) that have maintained exemplary high levels of reliability in their areas. These RTOs and ISOs have a primary obligation to maintain reliability, and through extensive experience have mandated what real time tools are necessary to this end in their areas. For instance, PJM Manual 1 Control Center and Data Exchange Requirements provides examples of many existing requirements for real time tools, including telemetry, alarms, assurance of date integrity, etc. The drafting team should be encouraged to make use of these existing resources and ensure that the new standard does not conflict with what has proven in practice to work well.
No additional comments.
Individual
Mark Thompson
Alberta Electric System Operator
Yes
Yes
Yes
Yes
Yes
Yes, as long as metrics for “availability” is sufficiently defined and would also include "response".
No
Yes
Reliability Standard
Should consideration of applicability to the network analysis requirements be given to those entities that have a minimal impact on the BES?
Individual
Greg Mason
Dynegy
No
The Generator Operator is not currently subject to this group of Standards. The Generator Operator should not be listed as a possible applicable entity without some technical justificatio from the SAR Drafting team.
Group
SERC OC Standards Review Group
No

See comments to Question 8.
Yes
See comments to Question 8.
Yes
See comments to Questions 5 & 8.
Yes
No
The SERC OC Standards Review Group supports placing any requirements related to this SAR in the Certification process. As such, this conversation is premature at this time, and should be held with the industry when the final location of these requirements is decided. It is unclear at this time how performance metrics would be tracked or enforced if the requirements become certification requirements.
No
NERC should proceed only with extreme caution when "redefining" a commonly understood industry term. If there is a need to define a new concept that is somewhat close to the meaning of Real-time, NERC should label that concept something other than Real-time. Because the term "Real-time" is commonly understood in the industry, the definition for Real-time in the NERC Glossary could be deleted. As auditing staff attempts to assess compliance with requirements during a future audit, it should not have to determine the vintage of a definition that helps explain the intent of a requirement.
No
If a need later develops to make the GOP applicable, then a SAR could be generated to cover the GOP at that time
Certification Process
First and foremost, the requirements developed as a part of this SAR must focus on capability, not specific technologies. The BES must not follow the path of the nuclear industry which suffers today from having specific technologies designated in the plant design basis. Technologies are progressing faster than a requirements process can follow. Embedding a specific tool in certification also creates measurement difficulty as the state of the art advances, which further supports our assertion that specifying capability rather than technology is the correct approach.
Neither is applicable. The reliability of the BES is only as good as the weakest link, therefore, no variances should be allowed.
Individual
Kathleen Goodman
ISO New England Inc.
No
The specific tools used in Operations must be designed for and by the entity using those tools to meet NERC standards. NERC standards define the system performance expected of the entity. The standards should NOT also impose constraints on the tools and the characteristics and performance requirements of those tools that are used by the entity to meet the expected system performance.
No
The SAR scope while limiting itself to Alarming, Telemetry and Network Analysis does not excuse the fact that operational tools and their characteristics should NOT be mandated by NERC standards. Mandating tools and their characteristics will stifle innovation and will overlook the local characteristics that must be addressed by the affected entities; and can impact Market structures and integration of renewal resources and adoption of smart grid devices.
No
The IRC does agree with the principle that NERC standards should define "What" not "How". However, by defining the characteristics of alarms, of telemetry and of Network Analysis, this SAR will be defining the HOW of an entity alarming, metering and analyzing its system. It seems obvious that analytic tools used to analyze a small co-op would be quite different from the analytic tools needed used to analyze a large RTO. The tools needed to analyze a stable/fixed load area would be quite different from a system with highly varying loads. The proposed standards will either create large inefficiencies for the smaller entity, or the standards will create inadequate

requirements for the larger entity.
No
See responses above.
No
Metrics of tool performance may sound like a great idea, however such standards will create a environment where tool characteristics become a goal unto itself, as opposed to an environment where ensuring transmission system reliability is the goal. NERC standards should be written to drive proper behavior and stipulate specific performance level of an entity to perform the tasks associated with the function it registers as. Those standards do not excuse that entity because the primary tool the entity uses is not available. Today's standards impose an implied obligation to have redundant / back-up tools to ensure that system reliability is maintained, regardless of tool's capability and availability in use. Tool metrics will create needless penalties, and are not drivers for proper behavior to ensure reliability. If a tool does not perform as this proposed SAR mandates, then the entity will be assessed non-compliant EVEN THOUGH the entity is meeting the primary goal of maintaining reliability. Tool unavailability is not the same as transmission performance problems. Bad tools do not equate to a bad behavior or system performance. The SRC would also note that there are currently requirements to ensure that tools are maintained and properly managed (see CIP-007 and IRO-002 R9). This suffices to ensure that the responsible entity has the needed tool capability to perform its tasks.
No
This proposal will more likely cause unintended consequences. The SAR requestor states that the redefinition is needed because of inherent time-delays in data. The outcome of a strict definition could be that all data must be sampled at the same universal time. The result of such a noble idea would be to impose unjustified costs on every entity in North America. These costs will result because not every point can be obtained at the exact same time unless the requesting entity has a huge capability to gather data simultaneously. A likely result of such standards will be unbundling responsibility into smaller entities. That in turn will result in less than wide-area analysis. That in turn will result in a less reliable bulk power system.
This question is unclear because the GOP is an applicable entity for NERC standards. Does a GOP need to do Network Analysis? If that is the question, the answer is NO; a GOP must operate a Generator, the TOP / RC must do the transmission analysis. Equally inappropriate would be to impose a mandate that the analysis tools on nuclear units have the same characteristics as the analysis tools on a CT.
Certification Process
First of all, we do not agree with creating a standard for tool characteristics or performance levels. If monitoring, alarming and analysis capabilities of an entity need to be specified and complied with, then we'd suggest that the certification process be used with the certification scope and requirements so clearly stipulated that the entity must demonstrate it has acquired such capabilities to perform the assigned tasks. The capability requirements are "one of" assessment. As such, they should be a part of the certification process, not an on going assessment of proper behavior or performance level of an entity which are is more suited in a standard.
There are numerous existing requirements for the RC, TOP, and BA to perform analysis and studies. Having these studies performed with what works best for the individual entity is important for reliability, not how they performed the study and analysis. The goal of a solid NERC Standard should be focused on the outcome.
Group
Bonneville Power Administration
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Reliability Standard
The Final report from the given link is missing the detailed data sections (everything after the introductions page 36). This requires minimum standards for tools - this is GOOD to have and the tools should be used. There should be a recognition of the effort to keep some of the tools working. Some of the requirements are overly prescriptive - not necessary with respect to external Interchange data. Not enough discrimination between primary entity EMS communication and ICCP exchange with external entities, which are mostly indirect reliability issues. There should be allowance for maintenance of the equipment: primary and secondary. The ICCP is sometimes handled over communications paths not under maintenance control of the TOP/BA. Sometimes equipment may break in unusual ways and take longer to diagnose and repair than the proposed criteria allowances would allow. Diagnosing the state estimator failure takes more time than the proposed criteria allows. The criteria is unrealistic in not recognizing that, as well as the orders of magnitude for a number of additional telemetered points required to reduce it. It's good to have frequent solutions, but it's not necessary to "measure it" and to penalize if it doesn't while diagnosing the trouble. This requires an increase in 24/7 staff to manage to the proposed criteria, but still takes time to diagnose/correct failed solutions. The contingency criteria is dependent on the state estimator, so there could be double jeopardy on proposed violations.
Group
Florida Municipal Power Agency, and its All-Requirements Project Participants, Beaches Energy Services and New Smyrna Beach
Yes
Yes
Yes
It is very important that we focus on the "what" and not the "how". Smaller systems can easily meet the functionality requirements of an eventual standards without the need for expensive additional software.
No
The proposed functions do not seem to address the "visualization" over a wide geographic area aspect of blackout recommendations. "Visualization" probably ought to be added as a function applicable to Reliability Coordinators.
No
The proposed metrics are primarily very IT system focused metrics that may not be directly correlated with the reliability of the Bulk Electric System. The metrics ought to be focused more on what is important to reliable operations, such as accuracy of information, timeliness of information, etc. If you think of it, in order to have accurate and timely information, an IT systems will need to be available, maintenance will have to have been coordinated, etc. The metrics proposed lean towards "how" and not "what".
Yes
The definition would go hand in hand with a key metric for the standard that probably ought to be added, timeliness of information. E.g., if a Transmission Owner is using a 10 minute rating for a line and it takes 5 minutes for the operator to even receive information that the line is beyond its normal rating, then the operator really only has about 5 minutes to make a decision and take action to reduce the loading on the line. Obviously, the more time the operator has to make decisions and take action in a deliberate fashion, the more reliable the power system. One key way to do this is to define "real-time" with a reasonable time delay maybe 3 minutes.
No

Why would a GOP have need for this? Most GOPs are radial to the interconnection point, so a contingency analysis will reveal nothing. The TOPs and RC will already be including the loss of generation or other contingencies in their contingency analysis. The only real involvement with the GOP is their metering and RTUs if the TOPs, BAs and RCs are depending on the GOPs information as data points in the control systems. There could be a requirement that the GOPs provide data to the TOPs / BAs / RCs through metering, RTUs and communication links to the TOPs / BAs / RCs criteria, but that should be the extent of what is required of GOPs, and, if that is a requirement of GOPs, then we would seriously need to consider LSEs and DPs as applicable entities to receive accurate load, losses and power factor information. This sort of requirement, however, probably belongs in the COM standards.
Reliability Standard
Not aware of any.
Please do not confuse the roles of TOPs, BAs and RCs. A BA should not be required to have a contingency analysis tool of transmission lines since that is not their function. A TOP should not be required to monitor supply and demand balance since that is not their function. Clearly delineate what is required of each entity.
Group
FirstEnergy
Yes
Yes
Yes
We agree with this approach and we encourage the SAR and subsequent effort of the SDT to focus on the minimum requirements (tools) needed to provide an Adequate Level of Reliability (ALR). The standard(s) should be careful to avoid prescriptive language that mandates the use of what could be considered cutting edge technologies that would cause inefficient use of limited resources.
Yes
Yes
Yes
We agree with the SAR's recommendation to revisit the definition of Real-time. However, if revised, the SDT should carefully consider any unintended impacts a change in definition may have on other existing reliability standards that reference the existing term.
Yes
An SDT should always have the freedom to consider new or revised applicability in standards projects in an effort to enhance the Adequate Level of Reliability of the BES. However, in the case of this project, applicability to requirements related to real-time operating tools should only be considered for Generator Operators (GOP) with centrally located dispatch or control centers with control over multiple generation plants. The requirements must not apply to GOP located within a control room having responsibility for only a unit(s) located at a single plant location. Also, if the GOP is retained as a reliability function within the scope of this SAR, the SAR's Purpose statement should be revised to include a reference to and discussion regarding the intent of adding the GOP as an applicabe entity. Furthermore, there should be no expectation that a GOP would be performing network analysis of the BES and the standard(s) should be clear that those tools remain with the RC and TOP.
Reliability Standard
We are not aware of any.
1. This SAR should be careful to avoid development of redundant requirements that describe the tasks performed by responsible entities that rely upon the real-time tools. There are a number of existing standards with requirements already aimed at addressing alarming, telemetry, and network analysis within the BAL, COM, IRO, and TOP family of standards. To the extent the drafting team considers putting end-result expectations within new real-time tools standard(s) as proposed

by this SAR, these existing requirements should also be reviewed to consider moving them to the new standard(s). Alternatively, in lieu of creating new standard(s), the existing standards mentioned above could be considered for revision to describe the minimum technical expectations and management of the real-time tools as proposed by this SAR. 2. This SAR appears to be sharply focused on addressing aspects of alarming, telemetry and network analysis. The SAR DT should consider the May 5, 2009 report provided by the Chair of the NERC Operating Committee (OC), Gayle Mayo, titled "Operating Committee Report to Board of Trustees Technology Committee: Management of NERC Reliability Tools". The OC's report describes real-time tools that NERC manages that are relied upon by registered entities and the potential conflict of NERC managing the tools while also having responsibility for enforcing compliance enabled by the tools. The interim proposed solution recommended to establish a joint industry/NERC management group as an independent arm of NERC reporting to the NERC BoT. To the extent any of the reliability tools described in the OC's report have bearing on the focus of this SAR, it may be necessary to include requirements within the proposed standard(s) to adequately cover the OC's vision and responsibility of the proposed independent real-time tools management group. Additionally, the SAR DT should consider if applicability changes are needed within the proposed standard(s) to address the OC's proposal.
Individual
Julie Reichle
NorthWestern Energy
No
NorthWestern Energy agrees that there is a reliability-related need for proposed guidelines pertaining to alarming, telemetry, and network analysis. However, a proposed standard should only come after guidelines and criteria have been tested during a trial period. This way the feasibility or functionality of the established guidelines, for Real-time tools, can be tested and proven to be effective before a sanction standard is put in place.
No
NorthWestern Energy agrees that the scope of the SAR has merit for establishing guidelines, but not for developing a new standard. The functionality, performance, and management of Real-time tools for Reliability Coordinators, Transmission Operators, and Balancing Authorities need guidance and direction. However, the proposal for a new standard should be prolonged until reliability entities can implement real time practices, put forth from guidelines, and truly test the feasibility, functionality, performance, and management of Real-time tools
No
NorthWestern Energy agrees with this approach but not for the proposal/request of a standard. Guidelines that describe what needs to be done for the functionality, performance, and management of Real-time tools should be established for Reliability Coordinators (RC) first. Once a test and evaluation period is complete, then a new standard should be proposed for Transmission Operators (TOP) and Balancing Authorities (BA) with proper guidelines for implementation. RCs have the highest authority and wide area view of Interconnections, so it seems logical that new guidelines in this area should begin at the RC level first.
No
NorthWestern Energy agrees with the focus on alarming and telemetry for all three of the reliability entities mentioned (Reliability Coordinators, Transmission Operators, and Balancing Authorities). The focus on network analysis should only apply to RCs first and then to TOPs and BAs. Northwestern Energy would also recommend having alarming for telemetry data only. Northwestern energy would not recommend replacing real-time alarming values with state estimated values. Again here NorthWestern Energy believes that the focus on alarming, telemetry, and network analysis should begin with guidelines and criteria before a standard is proposed/requested.
No
Northwestern Energy agrees with the performance metrics; however the whole set will be applicable only for alarming and telemetry purposes. Furthermore, the metrics need to be tested and evaluated before a standard can be requested.
Yes
Northwestern Energy believes that a new definition which explains more about what is expected out of “Real Time” is needed. The current definition is vague and broad, a more defined timeframe would provide better operating criteria and guidelines to Reliability Coordinators, Transmission

Operators and Balancing Authorities
Yes
NorthWestern Energy agrees that a potential Standards Drafting Team should have the freedom to consider the GOP as an applicable entity. However, close consideration should be given to the NERC Functional Model to ensure that the focus of the proposed standard truly applies to a GOP or any NERC Registered Entity. Furthermore, the final decision on this matter should still reside with NERC.
Reliability Standard
Northwestern Energy would recommend putting it as a Reliability Standard only after it has been tested and proven to be effective, then the requirements can be recognized as a Reliability Standard.
Business Practice
Northwestern Energy would recommend implementing this only for RCs to test the feasibility and functionality of the established guidelines on a trial period. If the guidelines prove to be effective then it can be implemented for TOPs and BAs with detailed operational guidelines.
As mentioned in the Real-Time Tools Survey Analysis and Recommendations Final Report (dated March 13, 2009), "RTBPTF believes that mandatory requirements for real-time tools for reactive reserve monitoring would be highly desirable; however, before such recommendations can be formulated, NERC must define technically justified and feasible-to-implement requirements for determining the appropriate amount and location of acceptable reactive reserves and clarifying how reliability coordinators should monitor these reserves." NorthWestern Energy believes that the same should hold true for alarms, telemetry, and network analysis. First guidelines, in these areas, should be established by NERC; then once implemented and proven effective by Reliability Coordinators these guidelines can be passed down to Transmission Operators and Balancing Authorities.
Individual
Brian Evans-Mongeon
Utility Services LLC
No
Standards will likely end up complicating the work of the real time operators. It will be impossible to devise tools that can deal with every possible scenario a RT operator will encounter. RT operators have been trained to assess the conditions at the time of the event or disturbance and to take all appropriate actions necessary to correct the condition.
No
Yes
When appropriate, standards should never prescribe how.
No
No
No
Yes
neither
Individual
Randy MacDonald
New Brunswick System Operator
No
NBSO does not believe that there is a reliability-related need for a standard specificaly for real time tools. Presently IRO and TOP standards address SOL and IROL awareness, detection and mitigation.

No comment
No comment
No comment
No comment
No comment
No comment
Certification Process
No comment
No comment
Group
NERC Standards Review Subcommittee
No
Based on the NERC BOT approval of PER-005-1, System Personnel Training, with a purpose of "To ensure that System Operators performing real-time, reliability-related tasks on the North American Bulk Electric System (BES) are competent to perform those reliability-related tasks. The competency of System Operators is critical to the reliability of the North American Bulk Electric System". The need for awareness as described by the RTBPTF in their 13 March 2008 report will be satisfied by RCs, TOPs, and BAs using a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators. By using PER-005's systematic approach to training, the process of ensuring system operator training needs never stops. All tasks will be required to be evaluated. In the detailed Description of the SAR it is proposed that Alarming, Telemetry and Network analysis is developed into a standard. These three functions are what system operators are already performing on a daily basis as described in the following Commission approved NERC Standards. IRO-002-1, R2 states, "Each RC shall determine the data requirements to support its reliability coordination tasks…" IRO-002-1, R5 states, "Each RC shall have detailed real – time monitoring capability…" IRO-002-1, R6 states, "Each RC shall monitor Bulk Electric System elements…" TOP-006-1, R1 states, "Each TOP, BA shall know the status of all generation and transmission resources available for use." TOP-006-1, R2 states, "Each RC, TOP, and BA shall monitor applicable transmission line status, real and reactive power flows, voltage, load tap changer settings, and status of rotating and static reactive resources". TOP-006-1, R4 states, "Each RC, TOP, and BA shall have information, including weather forecasts and past load patters, available to predict the system's near tern load pattern". TOP-006-1, R5 states, "Each RC, TOP, and BA shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action". TOP-008-1, R2 states, "Each TOP shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation…". TOP-008-1, R4 states, The TOP shall have sufficient information and analysis tools to determine the cause(s) of SOL violations".
No
Is the scope of this SAR to make operators aware of the alarms? Keep close to the practices of the recommendations of the Blackout report. Some type of caution should be expressed in that entities should not be told how to operate or address their alarms. A guideline would be more appropriate for this proposed standards action. The operating environment should focus on reliable system operation and focus for the system operation staff. For example the size of the entity's system or how the entity is structured will vary the type of the tools used and would make it difficult to make a one-size fits all standard. There is concern that the SAR may be expecting research and development of tools. This is not an appropriate use of a SAR.
Yes
This approach is stated on page 29 of NERCs "Drafting Team Guidelines". The Drafting Team must follow the guideline of establishing the "what" criteria for each requirement.
No
Each RC, TOP, and BA will have a different set of needs based on System Operator experience. This is why alarming, telemetry and network analysis should be training requirements, not a new standard. When a RC, TOP, and BA follow the systematic approach to training, these items should be part of the company's reliability - related task list. It is also not clear as to how far reaching standards for these functions would be. For example, MRO NSRS would not be in support of

anything that would infer the need to install duplicate instruments to provide information to a Reliability Coordinator (as in most cases this data is acquired by the TOP and BA and then passed to the RC).
No
Are the above metrics for the functions of Alarming, Telemetry, and Network analysis? A metrics is simple standard of measure. MRO NSRS understands that a metrics can be used in a measurement of a quantitative action, but how it would be used during "current operations" is not apparent. Perhaps this SAR should be more System Operator training based. If metrics were to be developed, any requirements created to impose metrics should allow for exceptions for extended outages of equipment for uncontrollable reasons. As written in the recommendation report, an outage on a real time tool for as short as a few hours could create significant non-compliance events, while not having any impact to the reliability of the system.
No
The current definition as listed in the NERC glossary is adequate. Real-Time is an understood concept within the industry.
No
A GOP follows dispatch instructions from a BA or prior committed schedule and will be held accountable if those instructions are not followed. There is no need to have GOPs within this SAR.
Certification Process
Please describe what the certification process is? Would this be for entities who wish to be registered as a BA, RC or TOP? Perhaps NERC could formulate a training program concerning these issues and give it to "all" entities to incorporate into their training programs. It would make a bigger impact vice having this SAR (and later proposed standard) be pushed around for many years before the Commission ever see it. If this is an Event recommendation, and it has taken 4 years to get a SAR, we have one slow process. Hire a contractor, put together a program based on the RTBPTF recommendations and allow All NERC Registered entities to train on it.
Business Practice
Please describe what the certification process is? Would this be for entities who wish to be registered as a BA, RC or TOP? Perhaps NERC could formulate a training program concerning these issues and give it to "all" entities to incorporate into their training programs. It would make a bigger impact vice having this SAR (and later proposed standard) be pushed around for many years before the Commission ever see it. If this is an Event recommendation, and it has taken 4 years to get a SAR, we have one slow process. Hire a contractor, put together a program based on the RTBPTF recommendations and allow All NERC Registered entities to train on it.
Use of industry groups such as the Transmission Owners and Operators Forum, and EPRI should be considered in development of best practices, guidelines, and tools for use in real time operations.
Individual
Derek Bleyle
South Carolina Electric and Gas
Yes
Yes
Yes
Yes
Yes
While we agree that the performance metrics should be part of the Standard, these metrics must allow for some level of equipment failure, communication failure, etc. and should not be a 100% performance requirement.
Yes
However, it should be noted in the Standard that there is an inherent delay in data acquistion, data processing, and data analysis. As such, things are not measured or calculated in real time per se, but are done as close to real time as practically possible. It should also be noted that caution should

be used if this term is re-defined as this is a commonly used and understood industry term.
No
The difference between a reliability standard and certification process needs to be clarified by NERC before this question can be answered.
Individual
Catherine Koch
Pugets Sound Energy
Yes
Yes
The SAR indicates it address selected recommendations in the RTBPTF Report. It appears the focus from the report is on 1. Reliability Toolbox and not recommendations listed in 2. Enhanced Operator Situational Awareness or 3. Address Six Major Issues to enhance the effectiveness of real-time tools which we would agree with at this time.
Yes
PSE suggests caution in defining "what" needs to be done if it leads to "how much" needs to be installed. An over abundance of telemetry data and alarms can create complexity when responding to an event and must be displayed effectively to be valuable.
Yes
No
Availability and quality appear to be performance metrics. Change management, maintenance coordination, and failure notification do not seem to be performance metrics as stated. These may also overlap significantly with the CIP standards and should be aligned effectively.
Yes
Suggest aligning with the Real Time Operations Time Horizon for which each requirement is assessed relative to a violation. This would ensure no confusion.
Yes
However, we suggest considering application of any of these standards is relative to the existance of a control center as defined or intended by the CIP standards. This would not impose an unnecessary burdan.
Reliability Standard
Individual
Jason Marshall
Midwest ISO
Yes
Midwest ISO supports the proposed standard to develop "requirements for the functionality, performance and management of Real-Time tools for Reliability Coordinators".
Yes
Yes
The Midwest ISO agrees the SAR should focus on "what" and not "how".
Yes
Yes
We largely agree with the need for the performance metrics; however, we caution the drafting

team to avoid duplicating already existing similar requirements. IRO-002 R9 already requires the RC to have approval for tool outages. CIP-007 already requires a change management process.
No
There does not appear to be any compelling reason to change the definition. It is likely any changes will only cause confusion.
No
There is no need to include the GOP. The GOP clearly has no need for network analysis capabilities.
Reliability Standard
The Midwest ISO believes the drafting team may need to develop both Reliability and Certification standards. Unfortunately, both options could not be selected.
The Midwest ISO believes this SAR and resulting standard should address what is required in terms of backup tools or more conservative operations when a tool is unavailable because no tool has 100% availability.
Group
IRC Standards Review Committee
No
The specific tools used in Operations must be designed for and by the entity using those tools to meet NERC standards. NERC standards define the system performance expected of the entity. The standards should NOT also impose constraints on the tools and the characteristics and performance requirements of those tools that are used by the entity to meet the expected system performance.
No
The SAR scope while limiting itself to Alarming, Telemetry and Network Analysis does not excuse the fact that operational tools and their characteristics should NOT be mandated by NERC standards. Mandating tools and their characteristics will likely stifle innovation and will overlook or otherwise fail to consider the variations in the local characteristics that must be addressed by the affected entities; and can impact Market structures, integration of renewable resources, and adoption of smart grid devices.
No
The IRC does agree with the principle that NERC standards should define “What” not “How”. However, by defining the characteristics of alarms, of telemetry and of Network Analysis, this SAR will be defining the HOW of an entity alarming, metering and analyzing its system. It seems obvious that analytic tools used to analyze a small co-op would be quite different from the analytic tools needed to analyze a large RTO. The tools needed to analyze a stable/fixed load area would be quite different from a system with highly varying loads. The proposed standards will either create large inefficiencies for the smaller entity, or the standards will create inadequate requirements for the larger entity.
No
See responses above.
No
Metrics of tool performance may sound like a great idea, however such standards will unintentionally create a environment where tool characteristics become a goal unto itself, as opposed to an environment where ensuring transmission system reliability is the goal. NERC standards should be written to drive proper behavior and stipulate specific performance level of an entity to perform the tasks associated with the function for which it is registered. Those standards do not excuse that entity because the primary tool the entity uses is not available. Today’s standards impose an implied obligation to have redundant / back-up tools to ensure that system reliability is maintained, regardless of tool’s capability and availability in use. Tool metrics will create needless penalties, and are not drivers for proper behavior to ensure reliability. If a tool does not perform as this proposed SAR mandates, then the entity will be assessed non-compliant EVEN THOUGH the entity is meeting the primary goal of maintaining reliability. Tool unavailability is not the same as transmission performance problems. Bad or malfunctioning tools, in themselves, do not equate to a bad behavior or system performance. The IRC would also note that there are currently requirements to ensure that tools are maintained and properly managed (see CIP-007 and IRO-002 R9). This suffices to ensure that the responsible entity has the needed tool capability to perform its tasks.

No
This proposal will more likely cause unintended consequences. The SAR requestor states that the redefinition is needed because of inherent time-delays in data. The outcome of a strict definition could be that all data must be sampled at the same universal time. The result of such a noble idea would be to impose unjustified costs on every entity in North America. These costs will result because not every point can be obtained at the exact same time unless the requesting entity has a huge capability to gather data simultaneously. A likely result of such standards will be unbundling responsibility into smaller entities. That in turn will result in less than wide-area analysis. That in turn will result in a less reliable bulk power system.
This question is unclear because the GOP is an applicable entity for NERC standards. Does a GOP need to do Network Analysis? If that is the question, the answer is NO; a GOP must operate a Generator, the TOP / RC must do the transmission analysis. Equally inappropriate would be to impose a mandate that the analysis tools on nuclear units have the same characteristics as the analysis tools on a CT.
Certification Process
First of all, we do not agree with creating a standard for tool characteristics or performance levels. If monitoring, alarming and analysis capabilities of an entity need to be specified and complied with, then we'd suggest that the certification process be used with the certification scope and requirements so clearly stipulated that the entity must demonstrate it has acquired such capabilities to perform the assigned tasks. The capability requirements are "one of" assessment. As such, they should be a part of the certification process, not an on going assessment of proper behavior or performance level of an entity which is more suited in a standard.
None
There are numerous existing requirements for the RC, TOP, and BA to perform analysis and studies. Having these studies performed with what works best for the individual entity is important for reliability, not how they performed the study and analysis. The goal of a solid NERC Standard should be focused on the outcome.
Individual
Dan Rochester
Independent Electricity System Operator
No
Tools used in Operations should be designed for and by the entity using those tools to meet NERC standards. NERC standards should stipulate the requirements that drive proper behavior and system performance expected of the entity. The standards should NOT also impose constraints on the tools and the characteristics and performance requirements of those tools that are used by the entity to meet the expected system performance.
No
Mandating tools and their characteristics will stifle innovation and will overlook the local characteristics that must be addressed by the affected entities, and can impact market structures and integration and management of other emerging issues such as renewal resources and adoption of smart grid devices.
No
We support the principle that NERC standards should define the "What" not the "How". However, by defining the characteristics of alarms, of telemetry and of Network Analysis, this SAR will be defining the HOW of an entity will alarm, meter and analyze its system. The "what", in our view, will be an entity's capability to monitor and analyze the power system and respond to alarmed situations. We do not think that a standard that stipulates the characteristics and performance level of tools is necessary.
No
We do not agree with the need for such a standard.
No
NERC standards should be written to drive proper behavior and stipulate specific performance level of an entity to perform the tasks associated with the function it registers as. Such standards should not excuse that entity for non-compliant because the primary tool the entity uses is not available. Today's standards impose an implied obligation to have redundant / back-up tools to ensure that system reliability is maintained, regardless of tool's capability and availability. Tool metrics will create unnecessary requirements and penalties, and are not drivers for proper behavior to ensure

reliability. If a tool does not perform the requirements that this proposed SAR mandates, then the entity will be assessed non-compliant even though the entity may be meeting the primary goal of maintaining reliability. We would also note that there are currently requirements to ensure that tools are maintained and properly managed (see CIP-007 and IRO-002 R9). This suffices to ensure that the responsible entity has the needed tool capability to perform its tasks.
No
This proposal will more likely cause unintended consequences. The SAR suggests that a redefinition is needed because of inherent time-delays in data. The outcome of a strict definition could be that all data must be sampled at the same universal time. The result of such a noble idea would be to impose unjustified costs on every entity in North America. These costs will result because not every point can be obtained at the exact same time unless the requesting entity has a huge capability to gather data simultaneously. A likely result of such standards will be smaller entities. That in turn will result in less than wide-area analysis. That in turn will result in a less reliable bulk power system. Real time operation is generally understood to be now and the next several minutes up to an hour. Any attempt to redefine the term Real Time to suit the purpose of tool characteristics or requirements will introduce problems or serious implications to the requirements governing real time operations.
This question is unclear because the GOP is an applicable entity for NERC standards. Does a GOP need to analyze the network performance? If that is the question, the answer is NO; a GOP needs only operate a generator, the TOP / RC must conduct network analyses.
Certification Process
First of all, we do not agree with creating a standard for tool characteristics or performance levels. If monitoring, alarming and analysis capabilities of an entity need to be specified and complied with, then we'd suggest that the certification process be used with the certification scope and requirements so clearly stipulated that the entity must demonstrate it has acquired such capabilities to perform the assigned tasks. The capability requirements are "one of" assessment. As such, they should be a part of the certification process, not an on going assessment of proper behavior or performance level of an entity which are more suited in a standard.
No
There already exist a number of standard requirements for the RC, TOP, and BA to conduct analyses and studies. Having these studies performed with what works best for the individual entity is essential for reliability, not how they performed the study and analysis.
Individual
Michael Gammon
Kansas City Power & Light
No
No. It is not the place for requirements and standards to dictate tools to operating entities. Standards and requirements are to specify what should be done for reliability not how to do it. The report is excellent as a best practices for the industry and should be left at that.
No
Yes
No
Operational situational awareness is a very complex mix of tools and displays of graphical and tabular information. It will be an extraordinarily difficult effort for a standard to capture that mix. The current standards and requirements that require sufficient monitoring, outage coordination, outage evaluation, mitigation plans for extreme operating conditions, etc. taken all together form a comprehensive assemblage of reliability principles that are sufficient to address the concerns of the August 14 black-out report.
No
See response to question #1.
Yes
Yes

Neither.
None.
None.

Consideration of Comments on Project 2009-02 — SAR for Real-time Reliability Monitoring and Analysis Capabilities

The Real-time Reliability Monitoring and Analysis Capabilities SAR Drafting Team (RTT SAR DT) thanks all commenters who submitted comments on the first draft SAR. The SAR was posted for a 30-day public comment period from June 10, 2009 through July 11, 2009. The stakeholders were asked to provide feedback on the documents through a special Electronic Comment Form. There were 42 sets of comments, including comments from more than 100 different people from over 60 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

The SDT has made numerous changes to the content of the SAR in an attempt to provide clarity to the SDT's position. This SAR is not about the Real-time Tools Best Practices Task Force Report nor is it about tools in general. It is about capabilities that functional entities must have in order to do their appointed tasks. The SAR DT does not contemplate naming specific tools or in telling functional entities how to do their jobs; the SAR is about the performance and capability of any tools utilized in the process of doing that job. The changes to the SAR are designed to bring those points across. Indeed, the SAR has been re-named to avoid any confusion with tools.

Due to the number of comments received and the apparent confusion about the intent of the SAR, the SAR DT has revised the language of the SAR to provide clarity and is requesting a second posting of this SAR.

This report includes all comments, re-sorted to make them easier to interpret; stakeholders can go the following location where they can read the submitted comments on the original Comment Forms.

http://www.nerc.com/filez/standards/Project2009-02_Real_Time_Tools.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, 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.

Index to Questions, Comments, and Responses

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.	Group	Jim Case, Chair of RTOSDT	NERC RTOSDT	X	X	X						X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Real Time Operations Standards Drafting Team	NERC	NA - Not Applicable	NA

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jalal Babik	Electric Market Policy			X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		SERC	6
2.	Mike Garton		NPCC	5
3.	Michael Gildea		RFC	3

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Al Adamson	New York State Reliability Council	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Manuel Couto	National Grid	NPCC	1
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	David Kiguel	Hydro One Networks Inc.	NPCC	1
12.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Michael Schiavone	National Grid	NPCC	1
17.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
18.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
19.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Kenneth D. Brown	Public Service Enterprise Group Companies	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Clint Bogan	PSEG Fossil LLC	RFC	5
2.	Scott Slickers	PSEG Power NY LLC	NPCC	5
3.	Ken Petroff	PSEG Nuclear LLC	RFC	5
4.	Gary Grysko	Odessa Power Partners LLC	ERCOT	5
5.	James Hebson	PSEG Energy Resources & Trade LLC	RFC	6
6.	Jeffrey Mueller	PSE&G	RFC	1, 3

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Jim Case	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Vinit Gupta	Entergy	SERC	1, 3
2.	Wayne Pourciau	Ga. Systems Operation Corp.	SERC	3

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

3.	Robert Kingsmore	Duke Energy Carolinas	SERC	1, 3, 5
4.	Larry Rodriquez	Entegra Power Group	SERC	5
5.	Joel Wise	TVA	SERC	1, 3, 5, 9
6.	Edd Forsythe	TVA	SERC	1, 3, 5, 9
7.	Bob Dalrymple	TVA	SERC	1, 3, 5, 9
8.	Eugene Warnecke	Ameren	SERC	1, 3, 5
9.	Brad Young	E. ON US	SERC	1, 3, 5
10.	Chad Randall	E. ON US	SERC	
11.	Alan Jones	Alcoa	SERC	1, 3, 5
12.	Monroe Landrum	Southern	SERC	1, 3, 5
13.	Raymond Vice	Southern	SERC	1, 3, 5
14.	Jim Busbin	Southern	SERC	1, 3, 5
15.	Hugh Francis	Southern	SERC	1, 3, 5
16.	Tim LeJeune	La. Generating	SERC	1, 3, 5
17.	John Rembold	Southern Illinois Power Cooperative	SERC	1, 3, 5
18.	Fred Krebs	Calpine	SERC	5
19.	Tony Halcomb	Cogentrix Energy	SERC	5
20.	Robert Thomasson	Big Rivers Electric Coop.	SERC	1, 3, 5
21.	Danny Dees	MEAG	SERC	1, 3, 5
22.	Tim Hattaway	PowerSouth	SERC	1, 3, 5
23.	Carter Edge	SERC	SERC	10
24.	Wes Davis	SERC	SERC	10
25.	John Troha	SERC	SERC	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Vassallo	Transmission Customer Service Engineering		1
2.	Jim Burns	Transmission Technical Operations		1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FE	RFC	4
2.	Dave Folk	FE	RFC	1, 3, 4, 5, 6
3.	John Reed	FE	RFC	1
4.	Andy Hunter	FE	RFC	1
5.	Rick Murphy	FE	RFC	1
6.	Larry Hartley	FE	RFC	3, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Carol Gerou	MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
2.	Neal Balu	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
3.	Ken Goldsmith	Alliant Energy	MRO	4
4.	Jim Haigh	Western Area Power Administration	MRO	1, 6
5.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
6.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
7.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
8.	Scott Nickels	Rochester Public Utilities	MRO	3, 4, 5, 6
9.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
10.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	RFC	2
2.	Lourdes Estrada-Salinero	CAISO	WECC	2
3.	Matt Goldberg	ISO-NE	NPCC	2
4.	Steve Myers	ERCOT	ERCOT	2
5.	James Castles	NYISO	NPCC	2

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Individual	Mike Davis	WECC Reliability Coordination										X
11.	Individual	Hugh Francis	Southern Company	X		X		X					
12.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
13.	Individual	Frank Gaffney	Florida Municipal Power Agency, and its All-Requirements Project Participants, Beaches Energy Services and New Smyrna Beach (FMPA)	X		X			X				
14.	Individual	Jason Shaver	American Transmission Company	X									
15.	Individual	Edward Stein	self								X		
16.	Individual	Scott Vidler	Hydro One	X		X							
17.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
18.	Individual	John Brockhan	CenterPoint Energy	X									
19.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
20.	Individual	Alan Gale	City of Tallahassee (TAL)					X					
21.	Individual	Rao Somayajula	ReliabilityFirst Corporation										X
22.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
23.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
24.	Individual	Jianmei Chai	Consumers Energy Company			X	X	X					
25.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
26.	Individual	Scott Nied	Con Edison System Operation	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
27.	Individual	Edward Davis	Entergy Services	X		X		X	X				
28.	Individual	Chris Scanlon	Exelon; ComEd, PECO and Exelon Generation	X		X		X	X				
29.	Individual	Kirit Shah	Ameren	X		X		X	X				
30.	Individual	Brent Ingebrigtson	E. On U.S.	X		X		X	X				
31.	Individual	Thomas J Bradish	RRI Energy					X	X				
32.	Individual	Mark Thompson	Alberta Electric System Operator		X								
33.	Individual	Greg Mason	Dynegy					X					
34.	Individual	Kathleen Goodman	ISO New England Inc.		X								
35.	Individual	Julie Reichle	NorthWestern Energy	X									
36.	Individual	Brian Evans-Mongeon	Utility Services LLC								X		
37.	Individual	Randy MacDonald	New Brunswick System Operator		X								
38.	Individual	Derek Bleyle	South Carolina Electric and Gas	X		X		X	X				
39.	Individual	Catherine Koch	Pugets Sound Energy	X									
40.	Individual	Jason Marshall	Midwest ISO		X								
41.	Individual	Dan Rochester	Independent Electricity System Operator (IESO)		X								
42.	Individual	Michael Gammon	Kansas City Power & Light	X		X		X	X				

1. Do you agree that either there is a reliability-related need for the proposed standards action?

Summary Consideration: There were three main themes expressed in the comments: (1) certification vs. standards; (2) tools vs. functionality or 'what vs. 'how'; and (3) new standards vs. revision of existing standards.

1. Industry was divided on whether there was a reliability related need for the proposed standards action. Some commenters responded that they thought certification was a preferable approach versus standards. The SAR DT has discussed this at length and provided sound reasoning why certification may not be an acceptable solution as detailed in the individual responses below.
2. The SAR never cites a specific tool but focuses on the functionality required for Real-time monitoring and analysis. An entity could use any tool that it has at its disposal as long as it meets the functionality, performance, and management requirements to be determined by an eventual standard. The SAR explicitly focuses on 'what' and not 'how'.
3. The SAR has been expanded to allow the eventual SDT to make the decision as to whether to write new standards or revise existing standards.

The SAR is not the Real-time Tools Best Practices Task Force (RTBPTF) Report. Many of the recommendations of the RTBPTF Report were not included in the SAR. A study group handled the disposition of the recommendations in the RTBPTF Report and crafted the SAR to handle only those recommendations that were deemed appropriate for standards activity. The eventual SDT is not bound to replicate the recommendations of the RTBPTF; it will be bound by the language of the SAR.

Organization	Yes or No	Question 1 Comment
SERC OC Standards Review Group	No	See comments to Question 8.
E. On U.S.	No	See comments for Question 8
Entergy Services	No	Entergy supports the SERC OC comments.
Response: Please see response to question 8 comments.		
MRO NERC Standards Review Subcommittee	No	Based on the NERC BOT approval of PER-005-1, System Personnel Training, with a purpose of "To ensure that System Operators performing real-time, reliability-related tasks on the North American Bulk Electric System (BES) are competent to perform those reliability-related tasks. The competency of System Operators is critical to the reliability of the North American Bulk Electric System". The need for awareness as described by the RTBPTF in their 13 March 2008 report will be satisfied by RCs, TOPs, and BAs using a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators. By using PER-005's systematic approach to training, the process of ensuring system operator training needs never stops. All tasks will be required to be evaluated.

Organization	Yes or No	Question 1 Comment
		In the detailed Description of the SAR it is proposed that Alarming, Telemetry and Network analysis is developed into a standard. These three functions are what system operators are already performing on a daily basis as described in the following Commission approved NERC Standards. IRO-002-1, R2 states, “Each RC shall determine the data requirements to support its reliability coordination tasks” “IRO-002-1, R5 states, “Each RC shall have detailed real “ time monitoring capability”“ IRO-002-1, R6 states, “Each RC shall monitor Bulk Electric System elements”“ TOP-006-1, R1 states, “Each TOP, BA shall know the status of all generation and transmission resources available for use.” TOP-006-1, R2 states, “Each RC, TOP, and BA shall monitor applicable transmission line status, real and reactive power flows, voltage, load tap changer settings, and status of rotating and static reactive resources”. TOP-006-1, R4 states, “Each RC, TOP, and BA shall have information, including weather forecasts and past load patters, available to predict the system’s near tern load pattern”. TOP-006-1, R5 states, “Each RC, TOP, and BA shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action”. TOP-008-1, R2 states, “Each TOP shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation”“. TOP-008-1, R4 states, The TOP shall have sufficient information and analysis tools to determine the cause(s) of SOL violations”.
Response: The SDT does not see where the first paragraph contains any relevance to this SAR. An entity could have a training program but you could be missing essential functions. The SAR doesn’t mention training. The standards cited in paragraph 2 are being revised and many of the requirements cited are suggested for retirement with the understanding that this project (Project 2009-02) will take on that responsibility.		
IRC Standards Review Committee	No	The specific tools used in Operations must be designed for and by the entity using those tools to meet NERC standards. NERC standards define the system performance expected of the entity. The standards should NOT also impose constraints on the tools and the characteristics and performance requirements of those tools that are used by the entity to meet the expected system performance.
ISO New England Inc.	No	The specific tools used in Operations must be designed for and by the entity using those tools to meet NERC standards. NERC standards define the system performance expected of the entity. The standards should NOT also impose constraints on the tools and the characteristics and performance requirements of those tools that are used by the entity to meet the

Organization	Yes or No	Question 1 Comment
		expected system performance.
IESO	No	Tools used in Operations should be designed for and by the entity using those tools to meet NERC standards. NERC standards should stipulate the requirements that drive proper behavior and system performance expected of the entity. The standards should NOT also impose constraints on the tools and the characteristics and performance requirements of those tools that are used by the entity to meet the expected system performance.
Response: The SAR never cites a specific tool but focuses on the functionality required for Real-time monitoring and analysis. An entity could use any tools that they have at their disposal as long as they meet the functionality, performance, and management requirements to be determined by an eventual standard.		
American Transmission Company	No	ATC believes that this should be addressed in the certification process, and if necessary a re-certification process. If that effort fails to achieve the overall goal of this SAR, (Minimum types of Real-time tools) then we would be more open to a standards develop project.
Response: Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP. Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives. The approach taken by the Standards Development Program is not to write new requirements that assess basic capabilities used to achieve performance measured through other requirements within the Reliability Standards. The SAR DT has researched the standards and concluded that other requirements do not presently exist to adequately cover the issues raised in the SAR. This SAR is the logical place and method for starting this process.		
CenterPoint Energy	No	CenterPoint Energy does not agree there is a reliability-related need for these proposed standards. The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations reports on page 19 First Energy (FE) had state estimation and contingency analysis tools. The "tools were not used to assess system conditions, violating

Organization	Yes or No	Question 1 Comment
		NERC Operating Policy 5, Section C, Requirement 3, and Policy 4, Section A, Requirement 5. FE personnel did not ensure that their Real-Time Contingency Analysis (RTCA) was a functional and effective EMS application as required by NERC Policy 2, Section A, Requirement 1." CenterPoint Energy agrees that real-time monitoring and network analysis tools are necessary however, CenterPoint Energy believes the appropriate forum to evaluate an entities tools and their use would be during the certification process for a RC, BA, or TOP. Items such as functionality, performance, and management of the available tools as well as availability and quality of the entity's tools and how the entity uses the tools in their operation could be measured as well.
Response: Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP. Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives. This SAR is the logical place and method for starting this process. .		
Xcel Energy	No	Several standards (IRO-002, TOP-006, TOP-008) already address the issues identified in this SAR. Rather than develop a new standard, we recommend evaluate or incorporate into an existing project for these standards.
Response: The SAR DT is not convinced that the cited standards truly address the issues of the SAR. It is possible that the eventual SDT could decide that the best method of solving the issue is to revise existing standards versus writing a new standard(s). To provide the eventual SDT with the greatest flexibility, the SAR DT has also checked the box for 'Existing Standard' as well as 'New Standard'.		
American Electric Power	No	AEP fully supports the need for entities to have an adequate tool set to operate in a reliable manner. However, it is AEP's belief that that reliability issues that this SAR intends to address are not resulting from a void in the reliability standards, but instead in the current certification processes. For example, some RTOs require that there are qualified systems in place prior to operating, while others require that individuals be certified. We would support that both elements are necessary, that is the right tool set verified and individuals having NERC certification, and that this occur in advance. Using the NERC certification process of functional entities to ensure that the right tool set is in place and operating correctly is preferable to allowing, by administrative registration alone, to begin operating and then, afterwards, try to invoke standards to address operating issues

Organization	Yes or No	Question 1 Comment
		that could have been avoided up-front. The certification process will need to also be modified beyond a single verification to a periodic process to ensure tools remain in place and are operating as expected.
Response: Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP. Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives. This SAR is the logical place and method for starting this process.		
City of Tallahassee	No	While it should be mandatory for the RC's to have these reliability tools, it is a "best practice" for many of the TO's. For many other TO's it would be overkill to have to establish these programs for a relatively small area that is fed from only a couple of lines. How does the applicability change for the size of the organization? Standards should be the MINIMUM needed to operate reliably, not a culmination of the industries "best practices".
Response: The SAR doesn't mention specific tools but functionality. Applicability can be constrained by an eventual SDT but not by a SAR DT. If applicability should be constrained, it probably wouldn't be exclusively by size but on the importance to the reliability of the BES. Standards are neither a minimum nor a culmination of best practices but rather what is needed to reliably operate the BES.		
RRI Energy	No	For the RC, TOP and BA "Yes" in some fashion but the SAR should not be applicable to a GOP. The GOP is not a system operator at the same level as a RC, TOP and BA. We do not have the information on the real time status of the BES. We do not know transformer loadings (other than our GSU), transmission line loadings, generator status (other than our own) and details of demand (local load and projected load). GOP's by statute are prohibited from knowing this information. A standard is not needed to mandate that we have real time tools. The GOP's EMS has the necessary tools for the GOP to comply with the direction given them by the RC, TOP and BA. The GOP is required by the IA and market rules to follow the direction of the RC, TOP and BA. GOP is included as a System Operator but we believe that the definition should be modified. We plan to submit a SAR to request this change.
Response: The SAR DT understands that not all elements of the SAR would apply to a Generator Operator. By checking the box for Generator Operator, the SAR		

Organization	Yes or No	Question 1 Comment
DT is providing the eventual SDT with the flexibility to include a Generator Operator as an applicable entity if necessary. If the Generator Operator isn't checked off as an applicable entity in the SAR, the SDT does not have the flexibility to add them back in later if they are needed. However, if the Generator Operator is cited in the SAR and the SDT doesn't feel that they are needed in a standard, they can leave them off the list of applicable entities. For these reasons, the SAR DT feels that Generator Operators should continue to be listed as potential applicable entities in the SAR.		
NorthWestern Energy	No	NorthWestern Energy agrees that there is a reliability-related need for proposed guidelines pertaining to alarming, telemetry, and network analysis. However, a proposed standard should only come after guidelines and criteria have been tested during a trial period. This way the feasibility or functionality of the established guidelines, for Real-time tools, can be tested and proven to be effective before a sanction standard is put in place.
Response: The eventual SDT has the flexibility to ask that any standard or standard revision go through a field test prior to implementation. Any field testing would be appropriate after the requirements have been drafted and prior to implementation.		
Utility Services LLC	No	Standards will likely end up complicating the work of the real time operators. It will be impossible to devise tools that can deal with every possible scenario a RT operator will encounter. RT operators have been trained to assess the conditions at the time of the event or disturbance and to take all appropriate actions necessary to correct the condition.
Response: The SAR doesn't mention specific tools but functionality. An entity could have a training program but you could be missing essential functions.		
New Brunswick System Operator	No	NBSO does not believe that there is a reliability-related need for a standard specificaly for real time tools. Presently IRO and TOP standards address SOL and IROL awareness, detection and mitigation.
Response: The SAR doesn't mention specific tools but functionality. The standards cited are being revised and many of the requirements cited are suggested for retirement with the understanding that this project (Project 2009-02) will take on that responsibility.		
Kansas City Power & Light	No	No. It is not the place for requirements and standards to dictate tools to operating entities. Standards and requirements are to specify what should be done for reliability not how to do it. The report is excellent as a best practices for the industry and should be left at that.
Response: The SAR doesn't mention specific tools but functionality. The SAR only gets into 'what' and specifically and explicitly stays away from telling you 'how'. The SAR is not the report.		
Manitoba Hydro		While this project has value, it should fall very low on the list of priorities. Other standards with greater risk to the reliability of the BES should be reviewed and revised before starting any new project.
Response: The Standards Committee sets the priorities for standards projects. They will determine when this SAR moves to standard status if at all.		

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	However we are very concerned that the action to revise existing standards or develop new standards could be overly prescriptive. The requirements should remain at a high level, and focus on the "what", as opposed to the "how". The Introduction to the "Real-Time Tools Survey Analysis and Recommendations Final Report" contains 40 recommendations related to new or revised reliability standards; and we believe that many of these recommendations are too prescriptive to be placed in a reliability standard. This SAR should not become a project to implement all 40 of those recommendations. Additionally, we believe that many of these items more properly belong in an entity certification process and not in a Standard. The certification process should address core functionality tools. Standards should be used to address the operational application of these tools. See response to question #8.
Response: The SAR DT does not intend that any standard coming out of this effort be overly prescriptive but the eventual SDT will actually be writing the standard(s). The SAR clearly states that it is dealing with 'what' and not 'how'. The SAR is not dealing with all 40 recommendations of the report, just the items that are explicitly called out in the SAR. Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP. Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives. The approach taken by the Standards Development Program is not to write new requirements that assess basic capabilities used to achieve performance measured through other requirements within the Reliability Standards. The SAR DT has researched the standards and concluded that other requirements do not presently exist to adequately cover the issues raised in the SAR. This SAR is the logical place and method for starting this process.		
Public Service Enterprise Group Companies	Yes	PSEG agrees that these items require a standard. However, creating a new standard for telemetry or other items may duplicate or conflict with what is in standards COM-001 & COM-002. The scope of this SAR should be expanded to include potential revisions to COM-001 and COM-002 to ensure that all three standards are complementary and consistent.
Response: The SAR DT does not believe that COM-002 is relevant to this SAR. However, COM-001 may be applicable. The SAR has been expanded to allow the		

Organization	Yes or No	Question 1 Comment
eventual SDT to make the decision as to whether to write new standards or revise existing standards.		
WECC Reliability Coordination	Yes	Our only concern is that the standard may outpace the available technology. Also, only tools that are applicable to all interconnections should be inlcuded in the standard.
Response: The SAR deals with functionality, not specific tools or technology. An eventual standard needs to cover more than just interconnections.		
Southern Company	Yes	In the absense of a certification process with re-certification, new standards should be established only if the same end can't be reached by revising existing standards. The RTBPTF's report gave several examples where real-time tools were mentioned but not well defined in existing standards. The SAR team should begin developing new standards only after they have determined that the same results can't be obtained by revising existing standards.
Response: The SAR has been expanded to allow the eventual SDT to make the decision as to whether to write new standards or revise existing standards. Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP. Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives. The approach taken by the Standards Development Program is not to write new requirements that assess basic capabilities used to achieve performance measured through other requirements within the Reliability Standards. The SAR DT has researched the standards and concluded that other requirements do not presently exist to adequately cover the issues raised in the SAR. This SAR is the logical place and method for starting this process.		
NERC RTO SDT	Yes	The RTOSDT technically takes no position on the reliability need for requirements that state which specific tools are required, as we believe this to be the answer to the "how" question as opposed to the "what" question which is the nature of a true reliability requirement.

Organization	Yes or No	Question 1 Comment
Hydro One	Yes	From my travels and contacts I've witnessessed extreme variances in tool capability among control centres. A lack of standards has allowed companies to cut corners while others strive for excellence.
Midwest ISO	Yes	Midwest ISO supports the proposed standard to develop “requirements for the functionality, performance and management of Real-Time tools for Reliability Coordinators”.
Electric Market Policy	Yes	
Northeast Power Coordinating Council	Yes	
Pugets Sound Energy	Yes	
South Carolina Electric and Gas	Yes	
Alberta Electric System Operator	Yes	
Exelon; ComEd, PECO and Exelon Generation	Yes	
Ameren	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery	Yes	
Con Edison System Operation	Yes	

Organization	Yes or No	Question 1 Comment
ReliabilityFirst Corporation	Yes	
Edward Stein (self)	Yes	
PacifiCorp	Yes	
FMPA	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
Response: Thank you for your response.		

2. Do you agree with the scope of the proposed standards action?

Summary Consideration: The SAR DT has changed the title and wording of the SAR to clarify the intent. The SAR has also been revised to allow for the possibility of revising existing standards as opposed to writing new standards.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	The scope of the SAR is too "invasive" to operations. The SAR should address the "output" requirements for the hardware and software-- operators must be provided with the information "results" they need to know to determine how the system is behaving real time, and also for possible system configurations (e.g. contingency analysis). Even though in the Brief Description section of the SAR it states "The intent is to describe "what" needs to be done but not "how" to do it." the performance and management of tools falls into the "how" category. While NPCC suports the material in the RTBPTF Real-time Tools Survey Analysis and Recommendations report, the Standard should be limited to stating the reliability objectives of the Real-time Tools, leaving to each Registered Entity that must comply with the Standard the decision on how they are going to meet these objectives.
Response: The SAR DT believes that the SAR does address output requirements and reliability objectives. However, the wording may not be as clear as it could be. Therefore, the SAR DT has changed the language of the SAR text to bring greater clarity to this task. The SAR is explicit in stating 'what' and not 'how'.		
Public Service Enterprise Group Companies	No	The scope of this SAR should be expanded to include potential revisions to COM-001 and COM-002 to ensure that all three standards are non-duplicative, complementary and consistent.
Response: The SAR DT does not believe that COM-002 is relevant to this SAR. However, COM-001 may be applicable. The SAR has been expanded to allow the eventual SDT to make the decision as to whether to write new standards or revise existing standards.		
MRO NERC Standards Review Subcommittee	No	Is the scope of this SAR to make operators aware of the alarms?Keep close to the practices of the recommendations of the Blackout report. Some type of caution should be expressed in that entities should not be told how to operate or address their alarms. A guideline would be more appropriate for this proposed standards action. The operating environment should focus on reliable system operation and focus for the system operation staff. For example the size of the entity's system or how the entity is structured will vary the type of the tools used and would make it difficult to make a one-size fits all standard. There is concern that the SAR may be expecting research and development of tools. This is not an appropriate use of a SAR.
Response: The SAR DT has changed the title and wording of the SAR to make the intent clearer. This revised wording should alleviate your concerns. The SDT will have the flexibility to constrain solutions to specific entities based on defined criteria so that one size doesn't fit all. There was no intent to mandate research and		

Organization	Yes or No	Question 2 Comment
development of tools, indeed, the SAR does not mention tools at all but emphasizes functionality.		
IRC Standards Review Committee	No	The SAR scope while limiting itself to Alarming, Telemetry and Network Analysis does not excuse the fact that operational tools and their characteristics should NOT be mandated by NERC standards.Mandating tools and their characteristics will likely stifle innovation and will overlook or otherwise fail to consider the variations in the local characteristics that must be addressed by the affected entities; and can impact Market structures, integration of renewable resources, and adoption of smart grid devices.
ISO New England Inc.	No	The SAR scope while limiting itself to Alarming, Telemetry and Network Analysis does not excuse the fact that operational tools and their characteristics should NOT be mandated by NERC standards.Mandating tools and their characteristics will stifle innovation and will overlook the local characteristics that must be addressed by the affected entities; and can impact Market structures and integration of renewal resources and adoption of smart grid devices.
IESO	No	Mandating tools and their characteristics will stifle innovation and will overlook the local characteristics that must be addressed by the affected entities, and can impact market structures and integration and management of other emerging issues such as renewal resources and adoption of smart grid devices.
Response: The SAR does not mention tools or their characteristics but emphasizes functionality.		
American Transmission Company	No	Please see our comment to question 1.
CenterPoint Energy	No	See response to Q1.
Manitoba Hydro		See comment for Question 1.
Response: Please see response to comments in question 1.		
Xcel Energy	No	There is concern that the SAR may be expecting research and development of tools. This is not an appropriate use of a SAR.
Response: There was no intent to mandate research and development of tools, indeed, the SAR does not mention tools at all but emphasizes functionality.		
American Electric Power	No	AEP believes that these actions are largely covered in the existing standards, including those shown below (Table 1) in the related SAR functions format. Repetition of requirements across multiple standards may create ambiguity if alternative requirements or methods are defined from one to the other. It also establishes the possibility of compounding violations for a single infraction. To the extent that new requirements are needed to address operational gaps, these could be made in the next

Organization	Yes or No	Question 2 Comment
		revision of the applicable existing standards, which is to be done on a periodic basis. TABLE I - Existing NERC Reliability Standards addressing Alarming, Telemetry, Network Analysis, Related Performance Metrics (Availability and Quality), and Processes and Procedures supporting Real-Time Tools (Change Mgt., Maintenance Coordination, and Failure Notification) : Alarming COM-001-1.1, does have some language related to the alarming of vital telecommunications facilities for voice and data. TOP-006-2 stress the importance of monitoring equipment to be used to 'alarm' or bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action. IRO-002-2, gives direction on the alarming management and awareness systems that need to be in place for the RC. Telemetry BAL-001-0, dealing with the ACE equation along with Control Performance Standards (CPS1 and CPS2) BAL-004-0, addressing Time Error Corrections BAL-005-0.1b, focuses on the telemetry components necessary for calculating the ACE equation BAL-006-1.1, tasks the Balancing Authorities to calculate and record hourly Inadvertent Interchange IRO-004-1, details the information that needs to be sent to the RC for reliability studies to be performed IRO-005-3, breaks down most of the parameters that a RC would need to receive for monitoring the BES TOP-002-2, highlights that changes in transmission facility status, along with ratings should be monitored and conveyed to the RC and BA TOP-005-2 is the Operational Reliability Information standard that lays out all of the data that needs to be updated at least every ten minutes TOP-006-2 is another standard focused on monitoring system conditions. VAR-001-1 also is offering details on what data should be pipelined back to the operating control centers from the BES. Network Analysis IRO-004-1, discusses the ability for the RC, TO, and BA to conduct next-day reliability analyses to ensure that the BES can be operated reliably. TOP-002-2, looks at the performance of current-day, next-day, and studies operational studies in conjunction with neighboring BA(s) and TO(s).

Organization	Yes or No	Question 2 Comment
		TOP-002-2, also address the thermal and voltage contingency analysis that needs to be performed. IRO-002-2, details the analysis that needs to take place via state estimation and other visualization tools.Performance Metrics for Availability and Quality AvailabilityAvailability BAL-005-0.1b, R8 looks at SCADA availability to gather data and calculate ACE. This requirement also address the availability of Frequency Metering equipment (99.95%). COM-001-1.1, stresses the diversity and redundancy of communication paths for the available exchange of Interconnection and operating information, internally and externally to AEP. EOP-008-0, emphasizes the development of a plan to ensure the monitoring and control of transmission, distribution and generation assets even with the loss of the Control Center. Quality BAL-005-0.1b, R17 breaks down the accuracy of the metering devices for time error and frequency measurements BAL-006-1.1, requires adjacent balancing authorities to have common megawatt-hour meters at the interconnection point. IRO-005-3, discusses the importance of operating to the most limiting element if there is a discrepancy between various entities monitoring the same facilities. TOP-006-2 generically states that sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions. Processes and Procedures supporting Real-Time Tools: Change Mgt., Maintenance Coordination, and Failure NotificationChange Management FAC-009-1, obligates the communication to RC(s), PA(s), TP(s), and TO(s) for new facility ratings on the Bulk Electric System. TOP-002-2, implies that there should be a facility change notification system in place for neighboring entities to use uniform line identifiers when referring to interconnected facilities. BAL-004-0, addressing Time Error Corrections Maintenance Coordination FAC-009-1, it is implied that these changes will be applied to the real time computer model with alterations to facility ratings on the Bulk Electric System. TOP-002-2, talks about each BA and TO maintaining accurate computer models for analyzing and planning system operations.Failure Notification IRO-005-3, highlights the responsibility to identify significant issues with ACE that can attribute to other errors, such as

Organization	Yes or No	Question 2 Comment
		frequency error and Time error.
Response: The SAR DT has revised the SAR to include the possibility of revising existing standards based on your research and comments. However, the SAR DT has only included TOP, IRO, and COM standards. The SAR DT does not believe it is necessary to include any other standards. The SAR DT researched the BAL, FAC, VAR, and EOP standards mentioned and has determined that they do not need to be included as they are not directly addressing the issues in the proposed scope of this SAR.		
City of Tallahassee	No	This should be targeted to the RC's initially. Let's get it up and running for them before we make it mandatory for the TO's and BA's. Many TO's and BA's will pursue them during the interim because they will know it is coming and can begin the long trek to get there.
Response: The SAR DT believes that Transmission Operators and Balancing Authorities are just as important to the reliability of the BES as are the Reliability Coordinators and thus should be included in this SAR from the outset.		
Duke Energy	No	We believe that the scope is too large to be manageable, and should be broken up into multiple projects.
Response: The SAR DT believes that the topics covered in the SAR are too closely related to be split up into different projects.		
RRI Energy	No	See comments from Question 1. This SAR should not include GOP in the applicability section.
Response: See response to question 1.		
NorthWestern Energy	No	NorthWestern Energy agrees that the scope of the SAR has merit for establishing guidelines, but not for developing a new standard. The functionality, performance, and management of Real-time tools for Reliability Coordinators, Transmission Operators, and Balancing Authorities need guidance and direction. However, the proposal for a new standard should be prolonged until reliability entities can implement real time practices, put forth from guidelines, and truly test the feasibility, functionality, performance, and management of Real-time tools
Response: Guidelines are only pertinent when associated with a particular standard or requirements. Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR to address the issues raised by FERC. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives. This SAR is the logical place and method for starting this process and will tie this together. The eventual SDT has the flexibility to ask that any standard or standard revision go through a field test prior to implementation. Any field testing would be appropriate after the requirements have been drafted and prior to implementation.		

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	No	
Utility Services LLC	No	
Response: The SAR DT is unable to respond since you didn't include any specific reasons for your disagreement. In the future, please provide specifics so that the SAR DT can adequately respond to your concerns.		
Hydro One	Yes	I agree if items such as wide area displays, identificaion of equipment outages (tagging, colours) which are crucial for visualization are being considered in other standards.
Response: The SAR does not tell you 'how' to use the functionality but 'what' an entity needs to do.		
SERC OC Standards Review Group	Yes	See comments to Question 8.
Entergy Services	Yes	Entergy supports the SERC OC comments.
Response: Please see response to comments in question 8.		
WECC Reliability Coordination	Yes	It appears that there may be a dollar and resource impact associated with the new and revised standards, so a phased approach may be required.
Response: The eventual SDT would interpret how any new or revised standard(s) would be implemented and utilize a phased approach if they believe it warranted.		
Pugets Sound Energy	Yes	The SAR indicates it address selected recommendations in the RTBPTF Report. It appears the focus from the report is on 1. Reliability Toolbox and not recommendations listed in 2. Enhanced Operator Situational Awareness or 3. Address Six Major Issues to enhance the effectiveness of real-time tools which we would agree with at this time.
Response: The SAR DT has been handed a scope of action that deals with specific recommendations but not all the recommendations in the RTBPTF Report.		
NERC RTOSDT	Yes	Again, the RTOSDT takes no position on the scope.
Southern Company	Yes	This SAR covers the concerns spelled out in the Real-time Tools Survey Analysis and Recommendations report.

Organization	Yes or No	Question 2 Comment
Electric Market Policy	Yes	
Midwest ISO	Yes	
South Carolina Electric and Gas	Yes	
Alberta Electric System Operator	Yes	
Exelon; ComEd, PECO and Exelon Generation	Yes	
Ameren	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery	Yes	
Con Edison System Operation	Yes	
ReliabilityFirst Corporation	Yes	
Edward Stein (self)	Yes	
PacifiCorp	Yes	
FMPA	Yes	

Organization	Yes or No	Question 2 Comment
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
Response: Thank you for your response.		

3. The SAR emphasizes functionality, performance, and management of tools as opposed to naming specific tools. The intent is to describe 'what' needs to be done as opposed to 'how' to do it. Do you agree with this approach? If not, please state specific reasons why not.

Summary Consideration: The majority of commenters agree with the approach of the SAR. Those who disagreed were generally okay with the concept but concerned about drifting into 'how'. The SAR DT has changed the title and wording of the SAR to make the intent even clearer to alleviate the concerns of those who disagreed.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	NPCC agrees that the SAR needs to emphasize the "what" that needs to be done to ensure the reliable and effective functionality, performance, and management of Real-time tools, not the "how" to do it. General categories of types of tools, such as state estimators, contingency analysis programs, etc. can be mentioned. How the results or outputs from those tools are generated, or the management of those tools outside the operating floor, are outside the scope of a standard. The results and of those tools and how they are used (and ease of use), are the most important issues.
Response: The SAR DT agrees that the SAR emphasizes the 'what' and not the 'how'. The SAR DT has revised the title and wording of the SAR to clarify the intent.		
IRC Standards Review Committee	No	The IRC does agree with the principle that NERC standards should define "What" not "How". However, by defining the characteristics of alarms, of telemetry and of Network Analysis, this SAR will be defining the HOW of an entity alarming, metering and analyzing its system. It seems obvious that analytic tools used to analyze a small co-op would be quite different from the analytic tools needed to analyze a large RTO. The tools needed to analyze a stable/fixed load area would be quite different from a system with highly varying loads. The proposed standards will either create large inefficiencies for the smaller entity, or the standards will create inadequate requirements for the larger entity.
ISO New England Inc.	No	The IRC does agree with the principle that NERC standards should define "What" not "How". However, by defining the characteristics of alarms, of telemetry and of Network Analysis, this SAR will be defining the HOW of an entity alarming, metering and analyzing its system. It seems obvious that analytic tools used to analyze a small co-op would be quite different from the analytic tools needed used to analyze a large RTO. The tools needed to analyze a stable/fixed load area would be quite different from a system with highly varying loads. The proposed standards will either create large inefficiencies for the smaller entity, or the standards will create inadequate requirements for the larger entity.

Organization	Yes or No	Question 3 Comment
IESO	No	We support the principle that NERC standards should define the "What" not the "How". However, by defining the characteristics of alarms, of telemetry and of Network Analysis, this SAR will be defining the HOW of an entity will alarm, meter and analyze its system. The "what", in our view, will be an entity's capability to monitor and analyze the power system and respond to alarmed situations. We do not think that a standard that stipulates the characteristics and performance level of tools is necessary.
Response: The SAR DT has changed the title and wording of the SAR to make the intent clearer. The SDT will have the flexibility to constrain solutions to specific entities based on defined criteria so that one size doesn't fit all.		
American Electric Power	No	While we do agree that "what," not "how," is the correct approach to describe the required real time tools, we believe it should be established in the certification process as described in item #1 above. While it is easy to say we will confine ourselves to "what," it's difficult to prevent establishing criteria that inadvertently leads to a particular "how." Should "how" occur, it limits opportunities for improvements and innovation, and could hamper better results. AEP agrees with this approach of describing "what" needs to be done, as opposed to "how" to do it, as this preferred approach encourages new technology development in achieving the intent of the standard.
Response: Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP. Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives. The approach taken by the Standards Development Program is not to write new requirements that assess basic capabilities used to achieve performance measured through other requirements within the Reliability Standards. The SAR DT has researched the standards and concluded that other requirements do not presently exist to adequately cover the issues raised in the SAR. This SAR is the logical place and method for starting this process. The SAR DT has changed the wording of the SAR to make the intent clearer. This should alleviate any concerns as to drifting towards a 'how'.		
City of	No	While I can appreciate NERC trying to avoid mentioning specific brand names, there is no point in not saying you have to have a

Organization	Yes or No	Question 3 Comment
Tallahassee		Contingency Analysis Program if that is what you want us to have. The continued interpretation of what NERC wants becomes a guessing game and we don't find out that we guessed wrong until we are audited.
Response: The SAR DT believes that there are multiple ways to achieve the desired results and that emphasizing functionality is the best method to use in the SAR. This point of view seems to be supported by the comments received.		
NorthWestern Energy	No	NorthWestern Energy agrees with this approach but not for the proposal/request of a standard. Guidelines that describe what needs to be done for the functionality, performance, and management of Real-time tools should be established for Reliability Coordinators (RC) first. Once a test and evaluation period is complete, then a new standard should be proposed for Transmission Operators (TOP) and Balancing Authorities (BA) with proper guidelines for implementation. RCs have the highest authority and wide area view of Interconnections, so it seems logical that new guidelines in this area should begin at the RC level first.
Response: Guidelines are only pertinent when associated with a particular standard or requirements. Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR to address the issues raised by FERC. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives. This SAR is the logical place and method for starting this process and will tie this together.		
FirstEnergy	Yes	We agree with this approach and we encourage the SAR and subsequent effort of the SDT to focus on the minimum requirements (tools) needed to provide an Adequate Level of Reliability (ALR). The standard(s) should be careful to avoid prescriptive language that mandates the use of what could be considered cutting edge technologies that would cause inefficient use of limited resources.
MRO NERC Standards Review Subcommittee	Yes	This approach is stated on page 29 of NERCs "Drafting Team Guidelines". The Drafting Team must follow the guideline of establishing the "what" criteria for each requirement.
Response: Thank you for your response.		
American Transmission Company	Yes	This approach should be incorporated into the certification/re-certification process.
Response: Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or		

Organization	Yes or No	Question 3 Comment
data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP. Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives. The approach taken by the Standards Development Program is not to write new requirements that assess basic capabilities used to achieve performance measured through other requirements within the Reliability Standards. The SAR DT has researched the standards and concluded that other requirements do not presently exist to adequately cover the issues raised in the SAR. This SAR is the logical place and method for starting this process.		
WECC Reliability Coordination	Yes	Although it appears that in the survey results that some items are specifically mandated.
Response: This is not the RTBPTF Report but a SAR and an eventual SDT will be bound by the words of the SAR. Nothing is mandated.		
Duke Energy	Yes	See our comment to question #1 above. We are concerned that if requirements are overly prescriptive, they are describing “how” instead of “what”.
Response: See response to question 1.		
Pugets Sound Energy	Yes	PSE suggests caution in defining "what" needs to be done if it leads to "how much" needs to be installed. An over abundance of telemetry data and alarms can create complexity when responding to an event and must be displayed effectively to be valuable.
Response: The SAR DT has changed the wording of the SAR to make the intent clearer. The SAR is focused on functionality.		
RRI Energy	Yes	Provided that the lack of the how will not cause an issue during an audit.
Response: An auditor can only enforce what is cited in the standard requirements. If the requirements are ‘what’, then the auditor can only enforce ‘what’.		
SERC OC Standards Review	Yes	See comments to Questions 5 & 8.

Organization	Yes or No	Question 3 Comment
Group		
Entergy Services	Yes	Entergy supports the SERC OC comments.
Response: Please see response to comments in questions 5 & 8.		
Public Service Enterprise Group Companies	Yes	The SAR should be limited to the “what” and not include the “how.” There are multiple equally effective ways of accomplishing the “how” and the decision as to which to use should be left to the impacted registered entities.
NERC RTOSDT	Yes	The RTOSDT agrees, however, it seems unlikely to be achievable in this case. Discussions surrounding analytical capabilities seemingly always devolve to specific tools.
Midwest ISO	Yes	The Midwest ISO agrees the SAR should focus on “what” and not “how”.
Utility Services LLC	Yes	When appropriate, standards should never prescribe how.
Exelon; ComEd, PECO and Exelon Generation	Yes	Agree that it is very important that a standard or certification process for validating Real Time Tools does not direct the applicable entities to use specific tools. Exelon endorses the "what", not the "how" approach as emphasized in the SAR.
Ameren	Yes	This is the correct approach. Tools will change over time. Defining the “what” should be the focus. Leave the technical “how” to those developing solutions.
Hydro One	Yes	It is the end result that counts - how you get there will within reason be driven by the standards.
Manitoba Hydro	Yes	Although the SAR does not intend to indicate “how to” perform the specific tasks/requirements, it may be useful to identify tools in a separate document that could be used to achieve the specific task without directing the use of a specific one.
FMPA	Yes	It is very important that we focus on the "what" and not the "how". Smaller systems can easily meet the functionality requirements of an eventual standards without the need for expensive additional software.
Kansas City Power & Light	Yes	

Organization	Yes or No	Question 3 Comment
Electric Market Policy	Yes	
Bonneville Power Administration	Yes	
South Carolina Electric and Gas	Yes	
Alberta Electric System Operator	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery	Yes	
Con Edison System Operation	Yes	
ReliabilityFirst Corporation	Yes	
Xcel Energy	Yes	
Edward Stein (self)	Yes	
Southern Company	Yes	
Response: Thank you for your response.		

4. The SAR focuses on alarming, telemetry, and network analysis. Do you agree that this is the right set of functions? If not, please state specific reasons why not.

Summary Consideration: The majority of respondents agree with the functions listed in the SAR. However, some concerns were raised that caused the SAR DT to change the title and wording of the SAR to make the intent clearer. Addition of other functions was suggested by some entities but there was no consensus on changing the scope in this regard.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	NPCC agrees that the functions stated are correct, but not all inclusive. The SAR needs to clarify that all of the functions contained in the Real Time Tools Report are not being addressed at this time due to the expansiveness of the RTBPTF report. There should be a fourth required functionality identified as Control. Control would include the application of and methods to ensure control capability is maintained at a control center and remote substations.
Response: The SAR explicitly states "This SAR addresses selected recommendations in the RTBPTF Report as determined by the Real-time Best Practices Standards Study Group: Project 2009-02." The study group organized to review the RTBPTF Report was restricted to those issues identified in the report.		
Public Service Enterprise Group Companies	No	If the scope of this SAR is expanded to include potential revisions to COM-001 and COM-002 to ensure that all three standards are non-duplicative, complementary and consistent, then PSEG concurs that alarming, telemetry and network analysis are the right set of functions.
Response: The SAR DT has expanded the scope of the SAR to include potential revisions to COM-001 but does not agree that COM-002 is pertinent to this SAR.		
MRO NERC Standards Review Subcommittee	No	Each RC, TOP, and BA will have a different set of needs based on System Operator experience. This is why alarming, telemetry and network analysis should be training requirements, not a new standard. When a RC, TOP, and BA follow the systematic approach to training, these items should be part of the company's reliability - related task list.It is also not clear as to how far reaching standards for these functions would be. For example, MRO NSRS would not be in support of anything that would infer the need to install duplicate instruments to provide information to a Reliability Coordinator (as in most cases this data is acquired by the TOP and BA and then passed to the RC).
Response: An entity could have a training program but you could be missing essential functions. The SAR does not mention duplicate instruments. The SAR only speaks to 'what'; 'how' things are done would be left to the individual entity.		
WECC Reliability	No	The survey results focus on additional items not listed above and do include data requirements such as day ahead study data

Organization	Yes or No	Question 4 Comment
Coordination		requirments, path limts requirement and special protection schemes monitoring applicability.
Response: The SAR is not dealing with all 40 recommendations of the report, just the items that are explicitly called out in the SAR.		
FMPA	No	The proposed functions do not seem to address the "visualization" over a wide geographic area aspect of blackout recommendations. "Visualization" probably ought to be added as a function applicable to Reliability Coordinators.
Response: The SAR DT believes that visualization is derived from the functionality that is spelled out in the SAR. Therefore, it is not needed as a separate item in the SAR.		
Xcel Energy	No	It is not clear as to how far reaching standards for these functions would be. For example, we would not be in support of anything that would infer the need to install duplicate instruments to provide information to a Reliability Coordinator (as in most cases this data is acquired by the TOP and BA and then passed to the RC).
Response: The SAR does not mention duplicate instruments. The SAR only speaks to 'what'; 'how' things are done would be left to the individual entity.		
American Electric Power	No	As described in item #2 above, we believe that these areas of focus are already covered in the existing standards (Table I). NERC is actively involved in consolidating standards in the revision process as witnessed in Project 2006-03. Creating new standards unnecessarily would be counter productive to this trend.
Response: Please see the response for question 2.		
City of Tallahassee	No	See response to question 1. Network Analysis does not need to be a requirement for smaller TO's. Until we can provide some way of avoiding the large expense without a measurable increase in reliability, we should not be pushing this function onto the TO. The TO's SHOULD be responsible for providing the data needed to the RC so his model works properly.
Response: The SDT will have the flexibility to constrain solutions to specific entities based on defined criteria so that one size doesn't fit all.		
Ameren	No	The SAR should include all aspects of the "Reliability Toolbox" as defined in the RTBPTF report.
Response: The SAR is not dealing with all recommendations of the report, just the items that are explicitly called out in the SAR.		
RRI Energy	No	The SAR's focus on "alarming, telemetry and network analysis" I believe supports dropping GOP from the applicability. Our EMS contains the alarms and telemetry needed to comply with standards and market rules. What level of network analysis does the SAR contemplate a GOP performing? Further, if a GOP feels that it needs to have unit AVR mode telemetry to insure compliance to VAR-002 then the GOP will add that alarm to its EMS. An additional standard requirement is not needed for the GOP to have

Organization	Yes or No	Question 4 Comment
		the necessary real time tools to support ALR of the BES.
Response: The SAR DT understands that not all elements of the SAR would apply to a Generator Operator. By checking the box for Generator Operator, the SAR DT is providing the eventual SDT with the flexibility to include a Generator Operator as an applicable entity if necessary. If the Generator Operator isn't checked off as an applicable entity in the SAR, the SDT does not have the flexibility to add them back in later if they are needed. However, if the Generator Operator is cited in the SAR and the SDT doesn't feel that they are needed in a standard, they can leave them off the list of applicable entities. For these reasons, the SAR DT feels that Generator Operators should continue to be listed as potential applicable entities in the SAR.		
NorthWestern Energy	No	NorthWestern Energy agrees with the focus on alarming and telemetry for all three of the reliability entities mentioned (Reliability Coordinators, Transmission Operators, and Balancing Authorities). The focus on network analysis should only apply to RCs first and then to TOPs and BAs. Northwestern Energy would also recommend having alarming for telemetry data only. Northwestern energy would not recommend replacing real-time alarming values with state estimated values. Again here NorthWestern Energy believes that the focus on alarming, telemetry, and network analysis should begin with guidelines and criteria before a standard is proposed/requested.
Response: The SAR DT believes that Transmission Operators and Balancing Authorities are just as important to the reliability of the BES as are the Reliability Coordinators and thus should be included in this SAR from the outset. How one utilizes data for alarming would be up to the individual entity and is not specified in the SAR as the SAR emphasizes functionality and 'what' as opposed to 'how'. The SDT has the flexibility to ask that any standard or standard revision go through a field test prior to implementation. That is not a consideration for a SAR.		
Kansas City Power & Light	No	Operational situational awareness is a very complex mix of tools and displays of graphical and tabular information. It will be an extraordinarily difficult effort for a standard to capture that mix. The current standards and requirements that require sufficient monitoring, outage coordination, outage evaluation, mitigation plans for extreme operating conditions, etc. taken all together form a comprehensive assemblage of reliability principles that are sufficient to address the concerns of the August 14 black-out report.
Response: The SAR DT does not agree that the existing standards cover the issues of performance metrics or availability.		
Utility Services LLC	No	
IESO	No	We do not agree with the need for such a standard.
Response: Thank you for your response.		
IRC Standards Review	No	See responses above.

Organization	Yes or No	Question 4 Comment
Committee		
ISO New England Inc.	No	See responses above.
CenterPoint Energy	No	See response to Q1.
American Transmission Company	Yes	Please see our comment to question 1.
Response: Please see response to comments in question 1.		
Oncor Electric Delivery	Yes	Smaller entities operating within the bulk electric system may bear a higher burden than larger ones. The benefits of providing real-time network analysis for these smaller entities may be far less than the costs.
Response: The SDT will have the flexibility to constrain solutions to specific entities based on defined criteria so that one size doesn't fit all.		
Exelon; ComEd, PECO and Exelon Generation	Yes	Exelon suggests historical data (storage and retrieval) should also be considered as an appropriate function. Also, while these may be the right functions for Real Time Tools, a total systems approach should be emphasized as opposed to focusing on "silos" of information and functions, RTU data, hardware, software etc.
Response: This project, if authorized by the Standards Committee, will be restricted to the items identified in the SAR.		
Hydro One	Yes	Network analysis is so broad that many functions can be included in this category i.e. dynamic equipment ratings, short circuit analysis, breaker duty cyclee etc that this SAR can be as broad as required.
Response: The SAR has been clarified to more clearly indicate the intent of the SAR DT.		
NERC RTOSDT	Yes	The RTOSDT takes no position on this issue.
Electric Market Policy	Yes	

Organization	Yes or No	Question 4 Comment
South Carolina Electric and Gas	Yes	
Pugets Sound Energy	Yes	
Midwest ISO	Yes	
Alberta Electric System Operator	Yes	
Con Edison System Operation	Yes	
Entergy Services	Yes	
ReliabilityFirst Corporation	Yes	
Manitoba Hydro	Yes	
Duke Energy	Yes	
Consumers Energy Company	Yes	
Edward Stein (self)	Yes	
Southern Company	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 4 Comment
SERC OC Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
Response: Thank you for your response.		

5. The SAR details the need for performance metrics for availability, quality, change management, maintenance coordination, and failure notification. Do you agree that this is the correct set of metrics? If not, please state specific reasons why not.

Summary Consideration: The SAR DT has changed the title and wording of the SAR to provide greater clarity. The SAR has been revised to specify that any metrics will be vetted by the industry through the standards comment process.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	The statement in Question 5 should be worded "The SAR details the need for performance metrics for alarming, telemetry, and network analysis functionalities, with the considerations of availability, quality, change management, maintenance coordination, and failure notification." What is meant by the term "change management"?
Response: In the context of this SAR, change management is the process in which changes are implemented in a controlled manner by following pre-defined procedures.		
SERC OC Standards Review Group	No	The SERC OC Standards Review Group supports placing any requirements related to this SAR in the Certification process. As such, this conversation is premature at this time, and should be held with the industry when the final location of these requirements is decided. It is unclear at this time how performance metrics would be tracked or enforced if the requirements become certification requirements.
Entergy Services	No	Entergy supports the SERC OC comments.
Response: Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP. Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and		

Organization	Yes or No	Question 5 Comment
enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives. The approach taken by the Standards Development Program is not to write new requirements that assess basic capabilities used to achieve performance measured through other requirements within the Reliability Standards. The SAR DT has researched the standards and concluded that other requirements do not presently exist to adequately cover the issues raised in the SAR. This SAR is the logical place and method for starting this process.		
MRO NERC Standards Review Subcommittee	No	Are the above metrics for the functions of Alarming, Telemetry, and Network analysis? A metrics is simple standard of measure. MRO NSRS understands that a metrics can be used in a measurement of a quantitative action, but how it would be used during “current operations” is not apparent. Perhaps this SAR should be more System Operator training based. If metrics were to be developed, any requirements created to impose metrics should allow for exceptions for extended outages of equipment for uncontrollable reasons. As written in the recommendation report, an outage on a real time tool for as short as a few hours could create significant non-compliance events, while not having any impact to the reliability of the system.
Response: Yes, these metrics are for the identified functions. An entity could have a training program but you could be missing essential functions. The wording of the SAR has been revised to show that any performance metrics would have to be vetted by the industry as part of the standards comment process.		
IRC Standards Review Committee	No	Metrics of tool performance may sound like a great idea, however such standards will unintentionally create a environment where tool characteristics become a goal unto itself, as opposed to an environment where ensuring transmission system reliability is the goal.NERC standards should be written to drive proper behavior and stipulate specific performance level of an entity to perform the tasks associated with the function for which it is registered. Those standards do not excuse that entity because the primary tool the entity uses is not available. Today’s standards impose an implied obligation to have redundant / back-up tools to ensure that system reliability is maintained, regardless of tool’s capability and availability in use. Tool metrics will create needless penalties, and are not drivers for proper behavior to ensure reliability. If a tool does not perform as this proposed SAR mandates, then the entity will be assessed non-compliant EVEN THOUGH the entity is meeting the primary goal of maintaining reliability. Tool unavailability is not the same as transmission performance problems. Bad or malfunctioning tools, in themselves, do not equate to a bad behavior or system performance. The IRC would also note that there are currently requirements to ensure that tools are maintained and properly managed (see CIP-007 and IRO-002 R9). This suffices to ensure that the responsible entity has the needed tool capability to perform its tasks.
ISO New England	No	Metrics of tool performance may sound like a great idea, however such standards will create a environment where tool

Organization	Yes or No	Question 5 Comment
Inc.		characteristics become a goal unto itself, as opposed to an environment where ensuring transmission system reliability is the goal.NERC standards should be written to drive proper behavior and stipulate specific performance level of an entity to perform the tasks associated with the function it registers as. Those standards do not excuse that entity because the primary tool the entity uses is not available. Today's standards impose an implied obligation to have redundant / back-up tools to ensure that system reliability is maintained, regardless of tool's capability and availability in use. Tool metrics will create needless penalties, and are not drivers for proper behavior to ensure reliability. If a tool does not perform as this proposed SAR mandates, then the entity will be assessed non-compliant EVEN THOUGH the entity is meeting the primary goal of maintaining reliability. Tool unavailability is not the same as transmission performance problems. Bad tools do not equate to a bad behavior or system performance. The SRC would also note that there are currently requirements to ensure that tools are maintained and properly managed (see CIP-007 and IRO-002 R9). This suffices to ensure that the responsible entity has the needed tool capability to perform its tasks.
IESO	No	NERC standards should be written to drive proper behavior and stipulate specific performance level of an entity to perform the tasks associated with the function it registers as. Such standards should not excuse that entity for non-compliant because the primary tool the entity uses is not available. Today's standards impose an implied obligation to have redundant / back-up tools to ensure that system reliability is maintained, regardless of tool's capability and availability. Tool metrics will create unnecessary requirements and penalties, and are not drivers for proper behavior to ensure reliability. If a tool does not perform the requirements that this proposed SAR mandates, then the entity will be assessed non-compliant even though the entity may be meeting the primary goal of maintaining reliability. We would also note that there are currently requirements to ensure that tools are maintained and properly managed (see CIP-007 and IRO-002 R9). This suffices to ensure that the responsible entity has the needed tool capability to perform its tasks.
Response: The loss of functionality could result in lack of adequate situational awareness. Metrics are needed to measure the performance and availability of those functionalities required to maintain BES reliability. CIP standards refer to critical assets at a system level while this SAR is meant to apply to the functionality described within the SAR. IRO-002 only applies to the Reliability Coordinator and tools while this SAR is meant to apply to additional entities and functionality.		
Southern Company	No	Availability and quality would be acceptable measureable metrics.Change management, maintenance coordination, and failure notification are processes and would have to be measured through documentation.
Response: The SAR has been changed to address this comment.		
FMPA	No	The proposed metrics are primarily very IT system focused metrics that may not be directly correlated with the reliability of the Bulk Electric System. The metrics ought to be focused more on what is important to reliable operations, such as accuracy of information, timeliness of information, etc. If you think of it, in order to have accurate and timely information, an IT systems will need to be

Organization	Yes or No	Question 5 Comment
		available, maintenance will have to have been coordinated, etc. The metrics proposed lean towards "how" and not "what".
Hydro One	No	One thing not indicated under performance metrics is actual performance i.e. alarm bursts, state estimator solve time or frequency of run, contingency analysis completeion time. If a SE only runs every 30min and takes 10min to solve how effective is it?
Response: The SAR does not mention specific metrics. The SAR has been revised to specify that any metrics will be vetted by the industry through the standards comment process.		
American Transmission Company	No	If this SAR is continued then the team needs to provide more information about the proposed performance metrics. (i.e. Definition(s), Calculation(s), Exclusion(s) and Goal(s)) In addition, the team should gather and provide information that can support the establishment of a minimum performance level. Setting a performance level will require strong technical support.
Oncor Electric Delivery	No	“Quality” should not be included. “Quality” is fundamentally subjective and cannot be measured
Exelon; ComEd, PECO and Exelon Generation	No	Exelon agrees performance metrics are important but we seek clarification concerning how quality, maintenance coordination, failure notification and especially change management are to be measured.
NERC RTOSDT	Yes	The RTOSDT agrees that a set of metrics is useful. Further, the RTOSDT believes that NERC must grapple with the concept that no information system is perfect. That is, requirements that involve information systems should only specify a "designed" level of performance, not the actual level of performance. It is nonproductive to investigate and fine an entity for failing to have two scans of an RTU, for example. The intent of a requirement related to information systems should always allow for reasonable failover times if redundancy is required and should allow for something less than 6 sigma performance, especially considering that communication networks outside of the control of reliability entities may have at best 2 sigma performance.
Alberta Electric System Operator	Yes	Yes, as long as metrics for “availability” is sufficiently defined and would also include "response".
South Carolina Electric and Gas	Yes	While we agree that the performance metrics should be part of the Standard, these metrics must allow for some level of equipment failure, communication failure, etc. and should not be a 100% performance requirement.
Response: The SAR has been revised to specify that any metrics will be vetted by the industry through the standards comment process.		

Organization	Yes or No	Question 5 Comment
CenterPoint Energy	No	See response to Q1.
Kansas City Power & Light	No	See response to question #1.
Response: Please see response to question 1 comments.		
American Electric Power	No	AEP believes that these actions are largely covered in the existing standards, including those shown previously (Table 1) in the related SAR functions format. Repetition of requirements across multiple standards may create ambiguity if alternative requirements or methods are defined from one to the other. It also establishes the possibility of compounding violations for a single infraction. To the extent that new requirements are needed to address operational gaps, these could be made in the next revision of the applicable existing standards.In any case, if this SAR proceeds, it must be limited to the “what” issues of “availability” and “quality”, and NOT on the “How” issues of "change management", "maintenance coordination", and "failure notification."
Response: Please see responses to previous AEP comments.		
Xcel Energy	No	Any requirements created to impose metrics should allow for exceptions for extended outages of equipment for uncontrollable reasons. As written in the recommendation report, an outage on a real time tool for as short as a few hours could create significant non-compliance events, while not having any impact to the reliability of the system.
Response: The SAR has been revised to specify that any metrics will be vetted by the industry through the standards comment process. The SAR is not the recommendation report – an eventual SDT would be bound by the language of the SAR. The loss of functionality could result in lack of adequate situational awareness.		
City of Tallahassee	No	The SAR identifies 2 performance metrics, Availability and Quality. The remaining three functions are not metrics; they will be requirements to ensure the entities have them. The use of metrics for enforcement will become contentious. If I say I am sending data to the RC over my data link, but he says he is not getting it, who gets charged with the non-availability or reduced quality? If the problem is with a third party communication (Sprint, AT&T, etc) why should I get penalized for the “network” failure? There are too many things beyond the control of the entity to make it a “mandatory and enforceable” metric.
Response: The SAR has been changed to address this comment. An entity should be able to prove whether they sent the data and that will determine who is responsible.		

Organization	Yes or No	Question 5 Comment
Contracts with the 3rd party vendors should handle issues such as network failures. Someone has to bear the accountability for failures. The SAR has been revised to specify that any metrics will be vetted by the industry through the standards comment process.		
Duke Energy	No	These are good metrics, but they don't belong in a reliability standard. Performance metrics should be implemented and enforced as part of the certification process.
Response: Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP. Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives. This SAR is the logical place and method for starting this process.		
NorthWestern Energy	No	Northwestern Energy agrees with the performance metrics; however the whole set will be applicable only for alarming and telemetry purposes. Furthermore, the metrics need to be tested and evaluated before a standard can be requested.
Response: The intent of the SAR is that performance metrics are applicable to all functionality specified in the SAR. The SAR has been revised to specify that any metrics will be vetted by the industry through the standards comment process. The eventual SDT has the flexibility to ask that any standard or standard revision go through a field test prior to implementation. Any field testing would be appropriate after the requirements have been drafted and prior to implementation.		
Pugets Sound Energy	No	Availability and quality appear to be performance metrics. Change management, maintenance coordination, and failure notification do not seem to be performance metrics as stated. These may also overlap significantly with the CIP standards and should be aligned effectively.

Organization	Yes or No	Question 5 Comment
Response: The SAR has been changed to address this comment. CIP standards refer to critical assets at a system level while this SAR is meant to apply to the functionality described within the SAR.		
Utility Services LLC	No	
Response: The SAR DT is unable to respond since you didn't include any specific reasons for your disagreement. In the future, please provide specifics so that the SAR DT can adequately respond to your concerns.		
WECC Reliability Coordination	Yes	The word quality needs to be clearly defined and measurable.
Response: The SAR wording has been revised and 'quality' is no longer used.		
Manitoba Hydro	Yes	Manitoba Hydro agrees that this is the correct set of metrics; however the definition and measures defined in the Standard will have to be very specific and defendable in terms of improving reliability.
Response: The SAR DT agrees.		
Midwest ISO	Yes	We largely agree with the need for the performance metrics; however, we caution the drafting team to avoid duplicating already existing similar requirements. IRO-002 R9 already requires the RC to have approval for tool outages. CIP-007 already requires a change management process.
Response: CIP standards refer to critical assets at a system level while this SAR is meant to apply to the functionality described within the SAR. IRO-002 only applies to the Reliability Coordinator and tools while this SAR is meant to apply to additional entities and functionality.		
Ameren	Yes	
Con Edison System Operation	Yes	
Consumers Energy Company	Yes	

Organization	Yes or No	Question 5 Comment
ReliabilityFirst Corporation	Yes	
Edward Stein (self)	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
Electric Market Policy	Yes	
Public Service Enterprise Group Companies	Yes	
Response: Thank you for your response.		

6. The SAR proposes to re-define Real-time. Do you agree that a new definition is needed? If not, please state specific reasons why not. If possible, specific suggested wording for a new definition would be appreciated.

Summary Consideration: Due to the industry comments received, the SAR DT has decided to delete the re-definition of Real-time from the SAR.

Organization	Yes or No	Question 6 Comment
Public Service Enterprise Group Companies	No	If “real-time” is redefined in the NERC glossary, it will be necessary to analyze the impact of this definitional change in each of the over 100 usages of this term throughout the full body of standards. If there is a particular concern about the speed/accuracy of “real-time” for this standard, then the specific requirement should be specified in this standard and not as a general definitional change.
SERC OC Standards Review Group	No	NERC should proceed only with extreme caution when “redefining” a commonly understood industry term. If there is a need to define a new concept that is somewhat close to the meaning of Real-time, NERC should label that concept something other than Real-time. Because the term “Real-time” is commonly understood in the industry, the definition for Real-time in the NERC Glossary could be deleted. As auditing staff attempts to assess compliance with requirements during a future audit, it should not have to determine the vintage of a definition that helps explain the intent of a requirement.
Entergy Services	No	Entergy supports the SERC OC comments.
IRC Standards Review Committee	No	This proposal will more likely cause unintended consequences. The SAR requestor states that the redefinition is needed because of inherent time-delays in data. The outcome of a strict definition could be that all data must be sampled at the same universal time. The result of such a noble idea would be to impose unjustified costs on every entity in North America. These costs will result because not every point can be obtained at the exact same time unless the requesting entity has a huge capability to gather data simultaneously. A likely result of such standards will be unbundling responsibility into smaller entities. That in turn will result in less than wide-area analysis. That in turn will result in a less reliable bulk power system.
ISO New England Inc.	No	This proposal will more likely cause unintended consequences. The SAR requestor states that the redefinition is needed because of inherent time-delays in data. The outcome of a strict definition could be that all data must be sampled at the same universal time. The result of such a noble idea would be to impose unjustified costs on every entity in North America. These costs will result because not every point can be obtained at the exact same time unless the requesting entity has a huge capability to gather data simultaneously. A likely result of such standards will be unbundling responsibility into smaller entities. That in turn will

Organization	Yes or No	Question 6 Comment
		result in less than wide-area analysis. That in turn will result in a less reliable bulk power system.
Southern Company	No	If a NERC Glossary term used in other standards is re-defined than the meaning of those standards has been changed without revision. The IRO standards use real-time as a description of a planning horizon or describing the data being used. Personnel operating the bulk power system understand that real-time data can be several seconds to several minutes old. The team may want to define the limits of near real-time data.
Hydro One	No	It is a good discussion point but it is splitting hairs a bit. Real Time is what you see now whether it took 5 minutes to get all the information or SE to solve. If the concept is to define how long it takes to refresh the data i.e. a 2 second refresh then that will drive home performance.
Con Edison System Operation	No	Changing the definition would be confusing. Adding a new term or making people become familair with using the "real time" term and another term such as "future time" would seem to be logical also.
IESO	No	This proposal will more likely cause unintended consequences. The SAR suggests that a redefinition is needed because of inherent time-delays in data. The outcome of a strict definition could be that all data must be sampled at the same universal time. The result of such a noble idea would be to impose unjustified costs on every entity in North America. These costs will result because not every point can be obtained at the exact same time unless the requesting entity has a huge capability to gather data simultaneously. A likely result of such standards will be smaller entities. That in turn will result in less than wide-area analysis. That in turn will result in a less reliable bulk power system. Real time operation is generally understood to be now and the next several minutes up to an hour. Any attempt to redefine the term Real Time to suit the purpose of tool characteristics or requirements will introduce problems or serious implications to the requirements governing real time operations.
Edward Stein (self)	No	Wordsmithing the definition of real time is a huge waste of (real) time. Everyone knows that real time data is between two and five seconds old (maybe even longer) depending on the scan rate. There has been some type of sabotage reporting rule or requirement for over 30 years because it was the sexy and politically correct thing to do even though there was no way that a System Operator, with his office in the middle of a corn field, knew if the line trip was due to sabotage or not. Even when the troubleman arrived at the scene of the outage, he still may not be able to determine if the tower fell down because it was a sabotage event or a local farmer removing some of the tower's bracing in order to use the bracing to hold up his corn crib.
MRO NERC Standards Review Subcommittee	No	The current definition as listed in the NERC glossary is adequate. Real-Time is an understood concept within the industry.
American Electric Power	No	Real-time is a precisely NERC defined term. In addition the Real-time term is highly integrated in the existing standards. Re-defining the term could have a significant impact on a wide-range of existing standards.

Organization	Yes or No	Question 6 Comment
Midwest ISO	No	There does not appear to be any compelling reason to change the definition. It is likely any changes will only cause confusion.
RRI Energy	No	I was unable from the SAR to understand why their was a need to redefine Real-time.
CenterPoint Energy	No	The current definition is sufficient. Any inherent time delay involved in the acquisition and dissemination of data to system operation personnel is understood. While that delay should be minimized, there are technical and financial limits to what can be done.
ReliabilityFirst Corporation	No	I do not think a new defintion is needed.
Exelon; ComEd, PECO and Exelon Generation	No	Exelon does not endorse a re-definition of Real-time.
Xcel Energy	No	
Utility Services LLC	No	
Alberta Electric System Operator	No	
American Transmission Company		A new definition will likely be needed if this project moves into a standards development phase; otherwise the existing definition may be suitable. (The certification / re-certification may not need to define Real-time but only identify minimum tools required for certification.)
Response: The SAR has been revised and the re-definition of Real-time has been deleted due to industry comments on this topic.		
Northeast Power Coordinating Council	Yes	NPCC agrees that the current definition that exists in the NERC Glossary of Terms where Real-Time is defined as “Present time as opposed to future time” is inadequate and needs to be redefined. Suggested rewording is: Real-time: 1. Existing or presently occurring. 2. In an information gathering or analysis environment, real time data and a time window allowed for its processing.
Response: Other commenters pointed out the far reaching effects of changing this definition. The SAR DT has discussed this matter and decided that a new		

Organization	Yes or No	Question 6 Comment
definition is not required for this SAR. The re-definition of Real-time has been deleted from the SAR.		
FirstEnergy	Yes	We agree with the SAR's recommendation to revisit the definition of Real-time. However, if revised, the SDT should carefully consider any unintended impacts a change in definition may have on other existing reliability standards that reference the existing term.
FMPA	Yes	The definition would go hand in hand with a key metric for the standard that probably ought to be added, timeliness of information. E.g., if a Transmission Owner is using a 10 minute rating for a line and it takes 5 minutes for the operator to even receive information that the line is beyond its normal rating, then the operator really only has about 5 minutes to make a decision and take action to reduce the loading on the line. Obviously, the more time the operator has to make decisions and take action in a deliberate fashion, the more reliable the power system. One key way to do this is to define "real-time" with a reasonable time delay maybe 3 minutes.
Manitoba Hydro	Yes	Present or current time seem to mean the same. Suggested definition: The actual time at which an event occurs.
South Carolina Electric and Gas	Yes	However, it should be noted in the Standard that there is an inherent delay in data acquistion, data processing, and data analysis. As such, things are not measured or calculated in real time per se, but are done as close to real time as practically possible. It should also be noted that caution should be used if this term is re-defined as this is a commonly used and understood industry term.
Pugets Sound Energy	Yes	Suggest aligning with the Real Time Operations Time Horizon for which each requirement is assessed relative to a violation. This would ensure no confusion.
NERC RTOSDT	Yes	The RTOSDT takes no position on this at this time. However, unintended consequences may occur. This needs a lot more explanation to the industry.
Ameren	Yes	Clarification of this term could be beneficial. “Real Time” can indicate significantly different time periods depending on the point of view. With the advent of new technologies such as phasor measurement units with a much higher sample rate, real time takes a very different meaning as compared to the traditional “seconds” based sample rates utilized in most current EMS/SCADA systems.
NorthWestern Energy	Yes	Northwestern Energy believes that a new definition which explains more about what is expected out of “Real Time” is needed. The current definition is vague and broad, a more defined timeframe would provide better operating criteria and guidelines to Reliability Coordinators, Transmission Operators and Balancing Authorities

Organization	Yes or No	Question 6 Comment
NERC RTOSDT	Yes	The RTOSDT takes no position on this at this time. However, unintended consequences may occur. This needs a lot more explanation to the industry.
Oncor Electric Delivery	Yes	There will be an inherent delay in the processing of applications, processing of data and the identification of contingency measures related to real time analysis for as much as 15 minutes. On the other hand, typical telemetry updates of data to the user display are around 2-4 seconds.
Consumers Energy Company	Yes	The existing definition is not useful.
Kansas City Power & Light	Yes	
Duke Energy	Yes	
City of Tallahassee	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
WECC Reliability Coordination	Yes	
Response: Other commenters pointed out the far reaching effects of changing this definition. The SAR DT has discussed this matter and decided that a new definition is not required for this SAR. The re-definition of Real-time has been deleted from the SAR.		

7. The SAR includes the Generator Operator (GOP) as a possible applicable entity. Do you agree that a potential Standards Drafting Team should have the freedom to consider the GOP as an applicable entity? If not, please state specific reasons why not.

Summary Consideration: The SAR DT understands that not all elements of the SAR would apply to a Generator Operator. By checking the box for Generator Operator, the SAR DT is providing the eventual SDT with the flexibility to include a Generator Operator as an applicable entity if necessary. If the Generator Operator isn't checked off as an applicable entity in the SAR, the SDT does not have the flexibility to add them back in later if they are needed. However, if the Generator Operator is cited in the SAR and the SDT doesn't feel that they are needed in a standard, they can leave them off the list of applicable entities. For these reasons, the SAR DT feels that Generator Operators should continue to be listed as potential applicable entities in the SAR.

If the eventual SDT decides to include the Generator Operator, they will constrain the applicability to only those items that directly apply. Codes and statutes will be adhered to in any eventual standard.

Organization	Yes or No	Question 7 Comment
Electric Market Policy	No	Most Transmission Operators (TOP) and Reliability Coordinators (RC) typically operate out of one control facility with information that expands beyond that provided by facilities under their direct control. There are protocols for coordinating operations of multiple facilities operated by different entities. Most Generator Operators (GOP) operate out a control room that contains information ONLY on facilities directly under that GOP's control. They are no protocols for coordinated operation of generating facilities. GOPs are to follow directives of the TOP and RC. Also, the federal/state codes/standards of conduct may prohibit dissemination of certain information between the RC/TOP and GOP entities. We strongly believe that placing new compliance requirements in this SAR on all generators is beyond the scope of what GOPs should be functionally doing in almost all generation locations on the bulk electric system and hence advancement of this standard with the inclusion in GOP applicability will actually create unnecessary complexity in operating the bulk electric system.
Ameren	No	It states that there would be a focus on Alarming to alert on events and conditions affecting the state of the BES, Telemetry to provide status and analog values in real time (status of what?), and Network Analysis for simulating impact of what-if events. For Alarming, what action would a GOP take in response to an alarm, that would be independent of what GOP would be directed to do by TO or BA or RC? GOP is already subject to plenty of other NERC Reliability Standards that state that the GOP has to do what the BA/TO/RC tell him/her to do in order to preserve the BES integrity. For Telemetry, regarding status (if assume of Transmission Components) inreal-time operation, doesn't that violate FERC Code of Conduct, since GOP is not supposed to know about Transmission information that may give him/her an advantage in the market? And as for Network Analysis, that has nothing to do with a GOP.

Organization	Yes or No	Question 7 Comment
Response: The SAR DT understands that not all elements of the SAR would apply to a Generator Operator. By checking the box for Generator Operator, the SAR DT is providing the eventual SDT with the flexibility to include a Generator Operator as an applicable entity if necessary. If the Generator Operator isn't checked off as an applicable entity in the SAR, the SDT does not have the flexibility to add them back in later if they are needed. However, if the Generator Operator is cited in the SAR and the SDT doesn't feel that they are needed in a standard, they can leave them off the list of applicable entities. For these reasons, the SAR DT feels that Generator Operators should continue to be listed as potential applicable entities in the SAR. If the eventual SDT decides to include the Generator Operator, they will constrain the applicability to only those items that directly apply. Codes and statutes will be adhered to in any eventual standard.		
Public Service Enterprise Group Companies	No	Generator Operators do not fit within the scope of this standard. They do not have direct involvement in the matters covered by this SAR. Any necessary GOP actions or requirements would be covered in the interconnection or operating agreements between generators and the applicable entities.
SERC OC Standards Review Group	No	If a need later develops to make the GOP applicable, then a SAR could be generated to cover the GOP at that time
Entergy Services	No	Entergy supports the SERC OC comments.
MRO NERC Standards Review Subcommittee	No	A GOP follows dispatch instructions from a BA or prior committed schedule and will be held accountable if those instructions are not followed. There is no need to have GOPs within this SAR.
FMPA	No	Why would a GOP have need for this? Most GOPs are radial to the interconnection point, so a contingency analysis will reveal nothing. The TOPs and RC will already be including the loss of generation or other contingencies in their contingency analysis. The only real involvement with the GOP is their metering and RTUs if the TOPs, BAs and RCs are depending on the GOPs information as data points in the control systems. There could be a requirement that the GOPs provide data to the TOPs / BAs / RCs through metering, RTUs and communication links to the TOPs / BAs / RCs criteria, but that should be the extent of what is required of GOPs, and, if that is a requirement of GOPs, then we would seriously need to consider LSEs and DPs as applicable entities to receive accurate load, losses and power factor information. This sort of requirement, however, probably belongs in the COM standards.
American Electric Power	No	AEP does not believe that it is necessary to include the GOP as an applicable function for this SAR, as data requirements are specified in existing standards. As mentioned in Item #1, using the NERC certification process of functional entities to ensure that the right tool set is in place and operating correctly is preferable to allowing, by administrative registration alone, to begin operating and then, afterwards, try to invoke standards to address operating issues that could have been avoided up-front.

Organization	Yes or No	Question 7 Comment
Oncor Electric Delivery	No	Generator Operators provide alarming and telemetry for their own facilities and only a small amount of this data is typically available to assist in determining the security of the bulk power system. In addition, Generator Operators do not normally perform network analysis.
Exelon; ComEd, PECO and Exelon Generation	No	Exelon sees no value in including the Generator Operator in the standard applicability. Data exchange and communication requirements are covered in other standards such as the COM and IRO standards. Additionally, RTO's, BA's and Transmission Owners and Operators typically specify in Interconnection Guidelines, Operating or Reliability Agreements and Manuals, what data must be shared between the Reliability Entities and the Generator Operators so as to support Real-time operational analysis.
RRI Energy	No	See previous comments.
Dynegy	No	The Generator Operator is not currently subject to this group of Standards. The Generator Operator should not be listed as a possible applicable entity without some technical justificatio from the SAR Drafting team.
South Carolina Electric and Gas	No	
Midwest ISO	No	There is no need to include the GOP. The GOP clearly has no need for network analysis capabilities.
Response: The SAR DT understands that not all elements of the SAR would apply to a Generator Operator. By checking the box for Generator Operator, the SAR DT is providing the eventual SDT with the flexibility to include a Generator Operator as an applicable entity if necessary. If the Generator Operator isn't checked off as an applicable entity in the SAR, the SDT does not have the flexibility to add them back in later if they are needed. However, if the Generator Operator is cited in the SAR and the SDT doesn't feel that they are needed in a standard, they can leave them off the list of applicable entities. For these reasons, the SAR DT feels that Generator Operators should continue to be listed as potential applicable entities in the SAR.		
IESO		This question is unclear because the GOP is an applicable entity for NERC standards. Does a GOP need to analyze the network performance? If that is the question, the answer is NO; a GOP needs only operate a generator, the TOP / RC must conduct network analyses.
IRC Standards Review Committee		This question is unclear because the GOP is an applicable entity for NERC standards. Does a GOP need to do Network Analysis? If that is the question, the answer is NO; a GOP must operate a Generator, the TOP / RC must do the transmission analysis.Equally inappropriate would be to impose a mandate that the analysis tools on nuclear units have the same characteristics as the analysis tools on a CT.
ISO New England		This question is unclear because the GOP is an applicable entity for NERC standards. Does a GOP need to do Network Analysis?

Organization	Yes or No	Question 7 Comment
Inc.		If that is the question, the answer is NO; a GOP must operate a Generator, the TOP / RC must do the transmission analysis.Equally inappropriate would be to impose a mandate that the analysis tools on nuclear units have the same characteristics as the analysis tools on a CT.
Response: If the eventual SDT decides to include the Generator Operator, they will constrain the applicability to only those items that directly apply. Codes and statutes will be adhered to in any eventual standard.		
Pugets Sound Energy	Yes	However, we suggest considering application of any of these standards is relative to the existance of a control center as defined or intended by the CIP standards. This would not impose an unnecessary burdan.
Response: If the eventual SDT decides to include the Generator Operator, they will constrain the applicability to only those items that directly apply.		
FirstEnergy	Yes	An SDT should always have the freedom to consider new or revised applicability in standards projects in an effort to enhance the Adequate Level of Reliability of the BES. However, in the case of this project, applicability to requirements related to real-time operating tools should only be considered for Generator Operators (GOP) with centrally located dispatch or control centers with control over multiple generation plants. The requirements must not apply to GOP located within a control room having responsibility for only a unit(s) located at a single plant location. Also, if the GOP is retained as a reliability function within the scope of this SAR, the SAR's Purpose statement should be revised to include a reference to and discussion regarding the intent of adding the GOP as an applicabe entity.Furthermore, there should be no expectation that a GOP would be performing network analysis of the BES and the standard(s) should be clear that those tools remain with the RC and TOP.
Response: If the eventual SDT decides to include the Generator Operator, they will constrain the applicability to only those items that directly apply.		
NorthWestern Energy	Yes	NorthWestern Energy agrees that a potential Standards Drafting Team should have the freedom to consider the GOP as an applicable entity. However, close consideration should be given to the NERC Functional Model to ensure that the focus of the proposed standard truly applies to a GOP or any NERC Registered Entity. Furthermore, the final decision on this matter should still reside with NERC.
Hydro One	Yes	A lack of situation awarness, alarms and telemetry that ends up with a generator(s) contingency will have an impact on the reliability of an area so it is as important.
Edward Stein (self)	Yes	Although these GOP requirements should be part of the interconnection agreement between the Generator and the Transmission Provider, it may be more straight forward to have these requirements addressed in this SAR.

Organization	Yes or No	Question 7 Comment
NERC RTOSDT	Yes	The RTOSDT can see no reason to preclude the adding of the GOP at the SDT phase of the project.
City of Tallahassee	Yes	Generator data is an important set of data for real time modeling.
ReliabilityFirst Corporation	Yes	
Manitoba Hydro	Yes	
Duke Energy	Yes	
Consumers Energy Company	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
Utility Services LLC	Yes	
Alberta Electric System Operator	Yes	
Con Edison System Operation	Yes	
WECC Reliability Coordination	Yes	

Organization	Yes or No	Question 7 Comment
Southern Company	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
Response: Thank you for your response.		

8. Do you believe the proposed requirements should reside in a reliability standard or should be addressed as part of the certification process?

Summary Consideration: According to the comments received, the industry was evenly split on this issue.

Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP.

Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives.

The approach taken by the Standards Development Program is not to write new requirements that assess basic capabilities used to achieve performance measured through other requirements within the Reliability Standards. The SAR DT has researched the standards and concluded that other requirements do not presently exist to adequately cover the issues raised in the SAR.

This SAR is the logical place and method for starting this process.

Organization	Reliability Standard or Certification Process	Question 8 Comment
NERC RTOSDT	Certification Process	Discussions at the RTOSDT have generally yielded consensus that these are basically one-time requirements, at certification time, and which specify the "designed-in" level of performance, while not focusing on the actual performance in absolute terms. That is, any actual performance requirements should be statistically sound. For example, it is patently absurd to believe that BAL-005-0.1b R8, which requires ACE calculation at least every 6 seconds, is actually possible with real computer systems. On a design basis, this means that a hot backup with failover within a couple of minutes is required. On an actual performance basis, this is far better than the up-time

Organization	Reliability Standard or Certification Process	Question 8 Comment
		required of space shuttle computers. Something like 2 sigma or 3 sigma performance for actual results is quite possibly all that is needed for the uptime for these tools.
Electric Market Policy	Certification Process	
SERC OC Standards Review Group	Certification Process	First and foremost, the requirements developed as a part of this SAR must focus on capability, not specific technologies. The BES must not follow the path of the nuclear industry which suffers today from having specific technologies designated in the plant design basis. Technologies are progressing faster than a requirements process can follow. Embedding a specific tool in certification also creates measurement difficulty as the state of the art advances, which further supports our assertion that specifying capability rather than technology is the correct approach.
MRO NERC Standards Review Subcommittee	Certification Process	Please describe what the certification process is? Would this be for entities who wish to be registered as a BA, RC or TOP? Perhaps NERC could formulate a training program concerning these issues and give it to "all" entities to incorporate into their training programs. It would make a bigger impact vice having this SAR (and later proposed standard) be pushed around for many years before the Commission ever see it. If this is an Event recommendation, and it has taken 4 years to get a SAR, we have one slow process. Hire a contractor, put together a program based on the RTBPTF recommendations and allow All NERC Registered entities to train on it.
IRC Standards Review Committee	Certification Process	First of all, we do not agree with creating a standard for tool characteristics or performance levels. If monitoring, alarming and analysis capabilities of an entity need to be specified and complied with, then we'd suggest that the certification process be used with the certification scope and requirements so clearly stipulated that the entity must demonstrate it has acquired such capabilities to perform the assigned tasks. The capability requirements are "one of" assessment. As such, they should be a part of the certification process, not an on going assessment of proper behavior or performance level of an entity which is more suited in a standard.
Southern Company	Certification Process	These requirements need to be included in an entity's certification process that includes periodic re-certification. This would require entities to certify that they have the tools needed to perform these functions and mechanisms in place to continue to perform the functions.
American Transmission Company	Certification Process	and re-certification process

Organization	Reliability Standard or Certification Process	Question 8 Comment
CenterPoint Energy	Certification Process	See response to Q1.
American Electric Power	Certification Process	It is AEP's belief that that reliability issues that this SAR intends to address are not resulting from a void in the reliability standards, but instead in the current NERC functional entities certification processes. A participant should have, upfront, at least the tool set to operate at an adequate level. The certification process is the appropriate forum for checking the systems. Furthermore, the NERC functional entities certification process could provide periodic checks to maintain certification by ensuring that the tool set remains in place. The upfront verification becomes a must as one considers that potentially thousands of non-traditional generation facilities may be interconnected in the near term.
ReliabilityFirst Corporation	Certification Process	
Duke Energy	Certification Process	We believe that the high level requirements for functionality should be in the reliability standards, and that the certification process should contain performance metrics and procedures related to change management, maintenance coordination and failure notification. See response to question #1.
Entergy Services	Certification Process	Entergy supports the SERC OC comments.
Exelon; ComEd, PECO and Exelon Generation	Certification Process	Exelon believes the Certification Process as specified in the ROP, Organization Registration and Certification Manual, Appendix 5, would be the best way to verify that entities performing the reliability functions are adequately equipped to do so.
E. On U.S.	Certification Process	Certified entities have been determined as capable of meeting the all applicable requirements. A new standard setting forth requirements for the tools employed by registered entities to meet existing requirements is redundant. Moreover, having NERC establish either functional or technical specifications for real-time systems will stifle innovation and unnecessarily lead many entities, who are currently meeting existing requirements, to invest resources in altering and not necessarily improving their existing real-time tools. It is better to leave the development of functional and technical specifications of rapidly changing technology to buyers and responding vendors. A failure on the part of registered entities to employ adequate real-time systems will in all likelihood lead to non-compliance with one or more existing requirements. It is nonsensical to describe a system that enables its owner/operator to meet BES reliability requirements as in any way insufficient.

Organization	Reliability Standard or Certification Process	Question 8 Comment
RRI Energy	Certification Process	
ISO New England Inc.	Certification Process	First of all, we do not agree with creating a standard for tool characteristics or performance levels. If monitoring, alarming and analysis capabilities of an entity need to be specified and complied with, then we'd suggest that the certification process be used with the certification scope and requirements so clearly stipulated that the entity must demonstrate it has acquired such capabilities to perform the assigned tasks. The capability requirements are "one of" assessment. As such, they should be a part of the certification process, not an on going assessment of proper behavior or performance level of an entity which are is more suited in a standard.
New Brunswick System Operator	Certification Process	
IESO	Certification Process	First of all, we do not agree with creating a standard for tool characteristics or performance levels. If monitoring, alarming and analysis capabilities of an entity need to be specified and complied with, then we'd suggest that the certification process be used with the certification scope and requirements so clearly stipulated that the entity must demonstrate it has acquired such capabilities to perform the assigned tasks. The capability requirements are "one of" assessment. As such, they should be a part of the certification process, not an on going assessment of proper behavior or performance level of an entity which are more suited in a standard.
Northeast Power Coordinating Council	Reliability Standard	From the NERC Reliability Standards Development Procedure, "Reliability Standard" means a requirement to provide for reliable operation of the bulk power system??. The ideas proposed in this SAR meet that definition, and belong in a reliability standard. NPCC believes that the certification of a function is only a snapshot in time. With technology continuously changing, there needs to be a process that will continuously capture these changes. NPCC is of the opinion that the NERC Standards are living documents and are the best mechanism available to the industry for capturing these changes by the continuous updating of the standard's requirements included within.
Public Service Enterprise Group Companies	Reliability Standard	
Bonneville Power Administration	Reliability Standard	
FirstEnergy	Reliability Standard	

Organization	Reliability Standard or Certification Process	Question 8 Comment
WECC Reliability Coordination	Reliability Standard	
FMPA	Reliability Standard	
Edward Stein (self)	Reliability Standard	I am not sure what is meant by the certification process. I thought that the certification process was a one time deal. If the certification process is conducted annually, you may be able to not have this as a reliability standard. However if an entity loses their certification what happens to then and more important what happens to reliability.
Hydro One	Reliability Standard	
Manitoba Hydro	Reliability Standard	
Consumers Energy Company	Reliability Standard	If these requirements would reside in a certification process, they would be scrutinized only once ? during the certification process, and there would be no measurability of their ongoing presence, particularly with the demise of the Readiness Evaluation Program.
Con Edison System Operation	Reliability Standard	Reliability Standard. Not familiar with the Certication Process.
Alberta Electric System Operator	Reliability Standard	
NorthWestern Energy	Reliability Standard	Northwestern Energy would recommend putting it as a Reliability Standard only after it has been tested and proven to be effective, then the requirements can be recognized as a Reliability Standard.
Pugets Sound Energy	Reliability Standard	
Midwest ISO	Reliability Standard	The Midwest ISO believes the drafting team may need to develop both Reliability and Certification standards. Unfortunately, both options could not be selected.
Response: Thank you for your responses. Please see the summary consideration for question 8 for the SAR DT response.		

Organization	Reliability Standard or Certification Process	Question 8 Comment
MRO NERC Standards Review Subcommittee	Business Practice	Please describe what the certification process is? Would this be for entities who wish to be registered as a BA, RC or TOP? Perhaps NERC could formulate a training program concerning these issues and give it to "all" entities to incorporate into their training programs. It would make a bigger impact vice having this SAR (and later proposed standard) be pushed around for many years before the Commission ever see it. If this is an Event recommendation, and it has taken 4 years to get a SAR, we have one slow process. Hire a contractor, put together a program based on the RTBPTF recommendations and allow All NERC Registered entities to train on it.
Response: MRO appears to have submitted 2 identical comments – one for certification and 1 for business practices. The SAR DT is assuming that certification is the true response as that is in line with the question posed.		
NorthWestern Energy	Business Practice	Northwestern Energy would recommend implementing this only for RCs to test the feasibility and functionality of the established guidelines on a trial period. If the guidelines prove to be effective then it can be implemented for TOPs and BAs with detailed operational guidelines.
Response: The eventual SDT has the flexibility to ask that any standard or standard revision go through a field test prior to implementation. The eventual SDT could structure the field test to include a particular functional entity or all potentially affected functional entities.		
Utility Services LLC		neither
Kansas City Power & Light		Neither.
City of Tallahassee		While I still disagree with a need for it to be a standard, IF it is moved to the Certification process, how will you monitor it on an ongoing basis? How will you ensure the currently registered entities have the tools?
Ameren		Whether the eventual approach is determined to be new or updated Reliability Standards or changes to the Certification Process the decision should be left up to the SAR drafting team.
South Carolina Electric and Gas		The difference between a reliability standard and certification process needs to be clarified by NERC before this question can be answered.

Organization	Reliability Standard or Certification Process	Question 8 Comment
Response: Thank you for your responses. Please see the summary consideration for question 8 for the SAR DT response.		

9. If you are aware of the need for a regional variance or business practice that we should consider with this SAR, please identify it here.

Summary Consideration: No regional variances or specific business practices have been identified at this time.

Organization	Regional Variance or Business Practice	Question 9 Comment
Public Service Enterprise Group Companies		While PSEG is not aware of the specific need for a regional variance or business practice, the SAR should specify that the drafting team should consider and give deference to the long-standing requirements of RTOs and ISOs (as RC, BA, and TOP) that have maintained exemplary high levels of reliability in their areas. These RTOs and ISOs have a primary obligation to maintain reliability, and through extensive experience have mandated what real time tools are necessary to this end in their areas. For instance, PJM Manual 1 Control Center and Data Exchange Requirements provides examples of many existing requirements for real time tools, including telemetry, alarms, assurance of date integrity, etc. The drafting team should be encouraged to make use of these existing resources and ensure that the new standard does not conflict with what has proven in practice to work well.
NERC RTOSDT		N/A
Northeast Power Coordinating Council		It is to too early in the process to identify whether there will be a need for a regional variance or business practice to consider with this SAR. NPCC believes that it is premature to either determine or conclude that an impact will exist in the future.
SERC OC Standards Review Group		Neither is applicable. The reliability of the BES is only as good as the weakest link, therefore, no variances should be allowed.
FirstEnergy		We are not aware of any.
IRC Standards Review Committee		None
WECC Reliability Coordination		none at this time

Organization	Regional Variance or Business Practice	Question 9 Comment
FMPA		Not aware of any.
American Transmission Company		Not aware of anything that applies.
Edward Stein (self)		There shouldn't be any.
American Electric Power		There should not be differences in the required tool sets, based on regional differences, if the requirements stay at the “what” level.
Duke Energy		None
Con Edison System Operation		No comment.
Entergy Services		Entergy supports the SERC OC comments.
Exelon; ComEd, PECO and Exelon Generation		Not aware of the need for either.
Ameren		No comments
New Brunswick System Operator		No comment
IESO		No
Kansas City Power & Light		None.
Response: Thank you for your response.		

10. If you have any other comments on this SAR that you have not already provided in response to the prior questions, please provide them here.

Summary Consideration: The SAR has been revised to specify that any metrics will be vetted by the industry through the standards comment process. The SAR emphasizes functionality and not tools. The SAR deals only with 'what' and not 'how'.

<table>
<tr><th>Organization</th><th>Question 10 Comment</th></tr>
<tr><td>NERC RTOSDT</td><td>FERC Order 693, paragraphs 1659 to 1665, mandate the addition of a requirement in the TOP standards for a minimum set of analytical tools for carrying out TOP reliability functions and that relay closing phase angle data be presented to operations staff: Tools and capabilities are a very broad, yet specialized topic that demands industry input of a more focused nature than that possible in current Project 2007-03 (Real-time Operations) upon which the RTOSDT is working. The RTOSDT believes that the Subject Matter Experts (SMEs) that will be gathered in support of this SAR will be better qualified to address this issue, and to elicit industry input, than the operational SMEs supporting Project 2007-03. The RTOSDT is basing its response to FERC for this matter on this item being vetted and supported by Project 2009-02 as appropriate.</td></tr>
<tr><td colspan="2">Response: The SAR DT appreciates your support and will continue to work to get the SAR approved which will address the issues raised in your comment. However, the SAR emphasizes functionality as opposed to specific tools. This SAR does not handle data so the comment on relay closing phase angle data is not being considered by the SAR DT and should be handled within your Project 2007-03.</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>NPCC believes that this SAR serves as only a beginning for addressing Real Time Tools and should not be construed as all encompassing. What is the intention for addressing the input devices for these tools (i.e.--current transformers, potential devices, transducers)?</td></tr>
<tr><td colspan="2">Response: The SAR DT agrees that this SAR should not be considered as all encompassing. It is not the intent of this SAR to address input devices.</td></tr>
<tr><td>Bonneville Power Administration</td><td>The Final report from the given link is missing the detailed data sections (everything after the introductions page 36).This requires minimum standards for tools - this is GOOD to have and the tools should be used.

There should be a recognition of the effort to keep some of the tools working.

Some of the requirements are overly prescriptive - not necessary with respect to external Interchange data.

Not enough discrimination between primary entity EMS communication and ICCP exchange with external entities, which are mostly indirect reliability issues.</td></tr>
</table>

Organization	Question 10 Comment
	There should be allowance for maintenance of the equipment: primary and secondary. The ICCP is sometimes handled over communications paths not under maintenance control of the TOP/BA. Sometimes equipment may break in unusual ways and take longer to diagnose and repair than the proposed criteria allowances would allow. Diagnosing the state estimator failure takes more time than the proposed criteria allows. The criteria is unrealistic in not recognizing that, as well as the orders of magnitude for a number of additional telemetered points required to reduce it. It's good to have frequent solutions, but it's not necessary to "measure it" and to penalize if it doesn't while diagnosing the trouble. This requires an increase in 24/7 staff to manage to the proposed criteria, but still takes time to diagnose/correct failed solutions. The contingency criteria is dependent on the state estimator, so there could be double jeopardy on proposed violations.
Response: The RTBPTF Report is available on the NERC web site. **(http://www.nerc.com/filez/rtbptf.html)** Maintainability is included as a part of the SAR. The SAR is not the RTBPTF Report. It is a standalone document. There are no requirements at this time; they would be developed by the eventual SDT. At the SAR level, the SAR DT does not feel that there should be any discrimination. The eventual SDT should have the freedom to discriminate or not to discriminate as needed. The eventual SDT would have the capability to decide on allowances for maintenance. Someone is always responsible. This is normally handled in contracts. The eventual SDT would have the capability to decide on equipment repair criteria. There is no criterion at this time. This is a standalone SAR and is not the RTBPTF Report. The eventual SDT is bound by the language of the SAR and not what was in the Report. The SAR has been revised to specify that any eventual metrics will be vetted by the industry through the standards comment process. Furthermore, the SAR does not mention any tools but emphasizes functionality.	
FirstEnergy	1. This SAR should be careful to avoid development of redundant requirements that describe the tasks performed by responsible entities that rely upon the real-time tools. There are a number of existing standards with requirements already aimed at addressing alarming, telemetry, and network analysis within the BAL, COM, IRO, and TOP family of standards. To the extent the drafting team considers putting end-result expectations within new real-time tools standard(s) as proposed by this SAR, these existing requirements should also be reviewed to consider moving them to the new standard(s). Alternatively, in lieu of creating new standard(s), the existing standards mentioned above could be considered for revision to describe the minimum technical expectations and management of the real-time tools as proposed by this SAR. 2. This SAR appears to be sharply focused on addressing aspects of alarming, telemetry and network analysis. The SAR DT should consider the May 5, 2009 report provided by the Chair of the NERC Operating Committee (OC), Gayle Mayo, titled "Operating Committee

Organization	Question 10 Comment
	Report to Board of Trustees Technology Committee: Management of NERC Reliability Tools". The OC's report describes real-time tools that NERC manages that are relied upon by registered entities and the potential conflict of NERC managing the tools while also having responsibility for enforcing compliance enabled by the tools. The interim proposed solution recommended to establish a joint industry/NERC management group as an independent arm of NERC reporting to the NERC BoT. To the extent any of the reliability tools described in the OC's report have bearing on the focus of this SAR, it may be necessary to include requirements within the proposed standard(s) to adequately cover the OC's vision and responsibility of the proposed independent real-time tools management group. Additionally, the SAR DT should consider if applicability changes are needed within the proposed standard(s) to address the OC's proposal.
Response: 1. The SAR has been revised to allow for the possibility of revising existing standards. 2. The SAR can't deal with proposed changes such as mentioned here. It can only deal with what is in place at this time. Any future changes to management of tools at NERC would need to be handled when a final determination is made.	
MRO NERC Standards Review Subcommittee	Use of industry groups such as the Transmission Owners and Operators Forum, and EPRI should be considered in development of best practices, guidelines, and tools for use in real time operations.
Xcel Energy	Use of industry groups such as the Transmission Owners and Operators Forum, and EPRI should be considered in development of best practices and tools for use in real time operations.
Response: The Transmission Owners and Operators Forum (TOOF) is a private group with confidential documents. TOOF can always submit comments as a group for consideration in the standards development process. EPRI reports are generally private documents for members only. The SDT would consider any inputs available to them.	
IRC Standards Review Committee	There are numerous existing requirements for the RC, TOP, and BA to perform analysis and studies. Having these studies performed with what works best for the individual entity is important for reliability, not how they performed the study and analysis. The goal of a solid NERC Standard should be focused on the outcome.
ISO New England Inc.	There are numerous existing requirements for the RC, TOP, and BA to perform analysis and studies. Having these studies performed with what works best for the individual entity is important for reliability, not how they performed the study and analysis. The goal of a solid NERC Standard should be focused on the outcome.
IESO	There already exist a number of standard requirements for the RC, TOP, and BA to conduct analyses and studies. Having these studies performed with what works best for the individual entity is essential for reliability, not how they performed the study and analysis.
Response: The SAR DT agrees and this is why the SAR deals only with 'what' and not 'how'.	

Organization	Question 10 Comment
WECC Reliability Coordination	We have an overall concern that an implementation process needs to be coordinated to minimize the impact to organizations that do not have the current resources or dollars to immediately implement the proposed changes. Also, it appears the SAR requires specific procedures rather than guidelines for event mitigtion, which does not provide the operator or RC leaway to assess all the variabiles in the interconnection. The role and responsibility for each requirement also needs to be clearly defined.
Response: The standards development process mandates that an Implementation Plan be filed as part of any standard development. The eventual SDT would decide on the exact implementation timeframes. The SAR does not mention event mitigation. The title and wording of the SAR has been revised to provide greater clarity as to the intent of the SAR DT. The eventual SDT would define roles and responsibilities consistent with the approved Functional Model.	
FMPA	Please do not confuse the roles of TOPs, BAs and RCs. A BA should not be required to have a contingency analysis tool of transmission lines since that is not their function. A TOP should not be required to monitor supply and demand balance since that is not their function. Clearly delineate what is required of each entity.
Alberta Electric System Operator	Should consideration of applicability to the network analysis requirements be given to those entities that have a minimal impact on the BES?
Response: The eventual SDT would decide what entities are applicable for specific requirements.	
City of Tallahassee	- I must reiterate that a fully functional Network Analysis tool (Contingency Analysis) is a “Best Practice” and not a requirement for many TO’s and BA’s. I know of a case where the TO is not allowed to vote on Standard development because they do not own enough miles of transmission lines, but they would have to have a CA program by this SAR. - The following comments are directly related to the Real-Time Tools Survey Analysis and Recommendations (Final Report) but do apply to the SAR. - Too wide of a “wide area view” may be detrimental to many TO/BA’s also. If the RC is watching over the entire RC area, and the TO/BA is watching over a smaller portion with a large portion equivalized, and the RC’s model goes down because of bad telemetry in another part of the RC area, the TO/BA’s model may still be functional because it is not reliant upon the bad data for proper operation. - On page 27 of the Executive Summary, the RTBPTF identifies the need to address the definition of the Bulk Electric System. This should be done before any additional standards requiring the use of the definition are allowed to proceed. There is still not a good understanding of what it needs to be to ensure that it is reliable. Lets get this hurdle crossed before we make more references to it. - On page 17, Situational Awareness Practices: The first sentence “The task force concludes that documented conservative operations practices are a key element of situational awareness practices and thus includes conservative operations plans in its recommendations.” This recommendation appears contrary to the desires of FERC to operate closer to the edge to allow maximum trade to occur based on the ATC standards undergoing revision/review. We should not have competing standards. - On

Organization	Question 10 Comment
	page 25, Awareness of Load-Shed Capability: This "awareness" does no good if the operator does not pull the trigger. THIS is the major cause of the August 14, 2003 blackout and a recurrent theme of recent blackouts. The "word on the street" (from Compliance) is that if you have to shed load (an event), you will be investigated for compliance violations because you must have done something wrong to get to that condition. What message is that sending to the operators? - On page 29, Issue #6: Adequate Funding for Staffing for Real-Time Tools and Support Should be Ensured. This area could not be analyzed by the RTBPTF. However, it did not preclude them from making numerous recommendations to enact the Real-Time tools. I do not like creating standards or requirements without any idea of how it will financially impact entities. This WILL cost a significant amount of money to enact. While many entities (as evidenced by the participation in the survey") are already engaged in pursuing these standards, or want to, the financial burden created by making it mandatory and enforceable will have deleterious effect on reliability. The money is going to come from somewhere. Be it from rate increases or diversion of funds from other projects, delaying the construction needed to fix what is going to be shown on the CA program. The managers of the Reliability Entities are fully aware of the importance of supporting NERC Standards.
Response: The SAR emphasizes functionality, not specific tools. As far as the SAR DT knows, any registered entity is allowed to join a ballot pool. This is not the RTBPTF Report. This is a standalone SAR. The time to comment on the RTBPTF Report is long past. The eventual SDT will not be bound in any way to the RTBPTF Report but to the SAR wording.	
Duke Energy	The drafting team should be very careful not to replicate requirements in multiple standards. For example TOP-008-1 Requirement R4 currently states: "The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation."
Response: The SDT has a charge in their delegated responsibilities to avoid duplication of requirements.	
NorthWestern Energy	As mentioned in the Real-Time Tools Survey Analysis and Recommendations Final Report (dated March 13, 2009), "RTBPTF believes that mandatory requirements for real-time tools for reactive reserve monitoring would be highly desirable; however, before such recommendations can be formulated, NERC must define technically justified and feasible-to-implement requirements for determining the appropriate amount and location of acceptable reactive reserves and clarifying how reliability coordinators should monitor these reserves." NorthWestern Energy believes that the same should hold true for alarms, telemetry, and network analysis. First guidelines, in these areas, should be established by NERC; then once implemented and proven effective by Reliability Coordinators these guidelines can be passed down to Transmission Operators and Balancing Authorities.
Response: Guidelines are not enforceable. The SAR has been revised to specify that any metrics will be vetted by the industry through the standards comment process.	
Midwest ISO	The Midwest ISO believes this SAR and resulting standard should address what is required in terms of backup tools or more conservative

Organization	Question 10 Comment
	operations when a tool is unavailable because no tool has 100% availability.
Response: The SAR has been revised to specify that any metrics will be vetted by the industry through the standards comment process. The SAR emphasizes functionality and not tools.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard: Project 2009-02: Real-time Reliability Monitoring and Analysis Capabilities	
Original Request Date: June 4, 2009	
Revised Date: January 15, 2010	

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name: Jack Kerr	X	New Standard(s)
Primary Contact: Dominion Virginia Power	X	Revision to existing Standard
Telephone: 1.804.273.3393 Fax: 1.804.273.2405	☐	Withdrawal of existing Standard
E-mail: jack.kerr@dom.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.) The new or revised standard(s) will establish requirements for the functionality, performance, and change management of Real-time capabilities for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* dated April 2004, a principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools. In addition, the failure of control computers and alarm systems, incomplete tool sets, and the failure to supply network analysis tools with correct System data on August 14 contributed directly to this lack of situational awareness. Also, the need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations.

Recommendation 22 of the Blackout Report states "Evaluate and adopt better real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate real-time tools and their usage within the industry. The Task Force produced a report "*Real-Time Tools Survey*

Analysis and Recommendations", dated March 13, 2008 that included recommendations for the functionality, performance, and management of Real-time tools.

There are 2 directives in FERC Order 693 relating to minimum tool capabilities that need to be addressed. One directive pertains to IRO-002 and is described in paragraphs 905 & 906 of Order 693. The second directive pertains to TOP-006 and is described in paragraph 1660. These directives clearly indicate the desire for a minimum set of capabilities as opposed to specific tools. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC.

This SAR addresses selected recommendations in the RTBPTF Report as determined by the Real-time Best Practices Standards Study Group: Project 2009-02 and addresses the directives in Order 693 referenced above.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The scope of the SAR is to establish requirements for the monitoring and analysis capabilities provided to System Operators and used to support Real-time System Operations. The SAR addresses availability parameters, performance metrics, and procedures for failure notification, maintenance coordination, and change management. The intent is to describe 'what' needs to be done but not 'how' to do it.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Develop or revise standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, and procedures for failure notification, maintenance coordination, and change management (vetted by the industry through the Reliability Standards comment process)of functionality for:

- Monitoring power System data in Real-time.
- Exchanging power System data in Real-time.
- Emitting Real-time visible and audible signals to alert System Operators to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an independent process monitor (e.g., watchdog).
- Determining the current state of the BES.
- Evaluating the impact of 'what if' events on the current or future state of the BES.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	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.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	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.
X	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.
X	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 service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	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.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	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.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power 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 of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability 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
TOP-xxx	The TOP family of standards is undergoing revision. The eventual SDT should have the flexibility to revise these standards or write new standards as best fits the task.
IRO-xxx	The IRO family of standards is undergoing revision. The eventual SDT should have the flexibility to revise these standards or write new standards as best fits the task.
COM-001-1.1	The eventual SDT should have the flexibility to revise this standard or write new standards as best fits the task.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standard Authorization Request Form

Title of Proposed Standard	Project 2009-02: Real-time ~~Tools~~Reliability Monitoring and Analysis Capabilities
Original Request Date:	June 4, 2009
Revised Date:	January 15, 2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Jack Kerr	X	New Standard(s)
Primary Contact	Dominion Virginia Power	X	Revision to existing Standard
Telephone Fax	1.804.273.3393 1.804.273.2405	☐	Withdrawal of existing Standard
E-mail	jack.kerr@dom.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

The new or revised standard(s) ~~or standards~~ will establish requirements for the functionality, performance, and change management of Real-time ~~tools~~capabilities for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, dated April 2004, a principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools. In addition, the failure of control computers and alarm systems, incomplete tool sets, and the failure to supply network analysis tools with correct System data on August 14 contributed directly to this lack of situational awareness. Also, the need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations.

Recommendation 22 of the Blackout Report states "Evaluate and adopt better real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate real-time tools and their usage within the industry. The Task Force produced a report "*Real-Time Tools Survey Analysis and Recommendations*", dated March 13, 2008 that included recommendations for the functionality, performance, and management of Real-time tools.

There are 2 directives in FERC Order 693 relating to minimum tool capabilities that need to be addressed. One directive pertains to IRO-002 and is described in paragraphs 905 & 906 of Order 693. The second directive pertains to TOP-006 and is described in paragraph 1660. These directives clearly indicate the desire for a minimum set of capabilities as opposed to specific tools. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC.

This SAR addresses selected recommendations in the RTBPTF Report as determined by the Real-time Best Practices Standards Study Group: Project 2009-02 and addresses the directives in Order 693 referenced above.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The scope of the SAR is to establish requirements for the monitoring and analysis capabilities ~~functionality, performance, and management of tools~~ provided to System Operators and used ~~in~~to support ~~of~~ Real-time System Operations. The SAR addresses availability parameters, performance metrics, and procedures for failure notification, maintenance coordination, and change management. The intent is to describe 'what' needs to be done but not 'how' to do it.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Develop or revise ~~a~~ standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, and procedures for failure notification, maintenance coordination, and change management (vetted by the industry through the Reliability Standards comment process)of~~require~~ ~~the following~~ functionality for:

- Monitoring power System data in Real-time.
- Exchanging power System data in Real-time.
- ~~Alarming – Applications or methods that e~~Emitting Real-time visible and audible signals to alert System Operators to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an independent process monitor (e.g., watchdog).
- ~~Telemetry – Applications and methods that provide status and analog values in Real-time or near-Real-time operation.~~
- ~~Network analysis – Applications and methods to be used for determining the current state of the system~~
- Determining the current state of the BES.
- ~~and simulating~~Evaluating the impact of 'what if' ~~system~~ events on the current or

future state of the ~~system~~BES.

~~Develop a standard(s) to require that responsible entities meet identified performance metrics for the above listed functionalities including but not limited to the consideration of:~~

- ~~Availability~~
- ~~Quality~~

~~Those entities shall also have procedures for the above listed functionalities including but not limited to the consideration of:~~

- ~~Change management~~
- ~~Maintenance coordination~~
- ~~Failure notification~~

~~Revise the Glossary definition of Real-time given that the acquisition and dissemination of operating data has inherent time delays. The current definition of Real-time is: Current time, as opposed to future time.~~

•

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	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.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	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.
X	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.
X	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 service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	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.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	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.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power 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 of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability 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
TOP-xxx	The TOP family of standards is undergoing revision. The eventual SDT should have the flexibility to revise these standards or write new standards as best fits the task.
IRO-xxx	The IRO family of standards is undergoing revision. The eventual SDT should have the flexibility to revise these standards or write new standards as best fits the task.
COM-001-1.1	The eventual SDT should have the flexibility to revise this standard or write new standards as best fits the task.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 2nd Draft of SAR for Real-time Reliability Monitoring and Analysis Capabilities (Project 2009-02)

Please DO NOT use this form. Please use the electronic form located at the link below to submit comments on the 2nd draft of the standards for Real-time Reliability Monitoring and Analysis Capabilities (Project 2009-02). Comments must be submitted by **February 18, 2010**. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

http://www.nerc.com/filez/standards/Project2009-02_Real_Time_Tools.html

Background Information:

The Real-time Reliability Monitoring and Analysis Capabilities SAR Drafting Team (RTT SARDT) has made changes to the first posting of the SAR based on comments received from the industry. Major changes included:

- Changing the name of the project to more clearly indicate the intent of the SAR.
- Emphasizing that the SAR is about functionality and not about specific tools.

The Real-time Reliability Monitoring and Analysis Capabilities SAR Drafting Team would like to receive industry comments on this standard. Accordingly, we request that you include your comments on the electronic comment form located at the link above by **February 18, 2010**.

1. The Real-time Reliability Monitoring and Analysis Capabilities SAR DT has attempted to clarify the wording of the SAR to show that this SAR is focused on functionality and not on specific tools. In other words, this SAR addresses 'what' vs. 'how'. Do you agree that the revised SAR adequately allays industry concerns on being too prescriptive as to how the functionality will be addressed? If not, please provide recommended wording changes.

   ☐ Yes

   ☐ No

   Comments:

2. In the first set of questions, several entities suggested that this functionality should and could be handled through certification. The SAR DT has researched the issue and has compiled the following information:

   Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP.

   Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives.

   Given this information, do you believe that the issues addressed in the proposed SAR belong in the certification process? If you respond 'Yes', please provide details as to how the goals of the proposed SAR (including the Order 693 directives) could be accomplished within the certification process given that there is no re-certification process to ensure that the goals of the proposed SAR will be met by all applicable entities including those already certified.

   ☐ Yes

   ☐ No

   Comments:

3. The approach taken by the Standards Development Program is not to write new requirements that assess basic capabilities used to achieve performance measured through other requirements within the Reliability Standards. The SAR DT has researched the standards and concluded that other requirements do not presently exist

to adequately cover the issues raised in the SAR. Do you agree with this position? If not, please identify existing standard requirements that would apply and explain how these requirements accomplish the goals of the proposed SAR (including the Order 693 directives).

☐ Yes

☐ No

Comments:

4. Does the revised Detailed Description of the SAR provide sufficient details for the eventual Standard Drafting Team to execute the SAR? If not, please identify areas of insufficient detail and provide suggested wording for increased clarity.

☐ Yes

☐ No

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
January 19-February 18, 2010

Now available at: http://www.nerc.com/filez/standards/Project2009-02_Real-Time_Monitoring_Analysis_Capabilities.html

Project 2009-02: Real-time Reliability Monitoring and Analysis Capabilities
A second draft of the standard authorization request (SAR) has been posted by the Real-time Reliability Monitoring and Analysis Capabilities SAR Drafting Team. The team is seeking comments on the SAR **until 8 p.m. EDT on February 18, 2010**. The drafting team has also posted its consideration of industry comments received for the first draft of the SAR.

Instructions
Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Project2009-02_Real-Time_Monitoring_Analysis_Capabilities.html

Next Steps
The drafting team will draft and post responses to comments received during this period.

Project Background
The purpose of this project is to draft new or revised standard(s) that will establish requirements for the functionality, performance, and change management of real-time capabilities for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable system operations.

The SAR addresses selected recommendations in the RTBPTF Report http://www.nerc.com/filez/rtbptf.html as determined by the Real-time Best Practices Standards Study Group (the group that initiated the work on this project) as well as directives identified in Federal Energy Regulatory Commission (FERC) Order 693.

Applicability (as listed in the SAR)
Reliability Coordinator
Balancing Authority
Transmission Operator
Generator Operator

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.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (30 Responses)
Name (17 Responses)
Organization (17 Responses)
Group Name (13 Responses)
Lead Contact (13 Responses)
Question 1 (29 Responses)
Question 1 Comments (30 Responses)
Question 2 (25 Responses)
Question 2 Comments (30 Responses)
Question 3 (28 Responses)
Question 3 Comments (30 Responses)
Question 4 (24 Responses)
Question 4 Comments (30 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
The current draft of the SAR indicates the applicability to be intended to extend to RCs, BAs, TOPs, and GOPs. It also indicates the industry need was identified through the August 14 Blackout report and references FERC Order 693. This is misleading because: 1) The "tools" issues related to the August 14 Blackout were restricted to the TOP and RC functions and there was no indication that the BA or GOP tools were lacking in any respect. 2) FERC Order 693 stipulated (a) "ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator" and "The Commission approves TOP-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to TOP-006-1 through the Reliability Standards development process, as discussed below." As referenced in the "Related Standards" section, this endeavor is best suited under the responsibility of existing drafting teams working on the RC and TOP Standards sets. Or, in the alternative, as was commented in the first round of posting, these could be easily addressed through the Certification Process of the RC and TOP. There isn't an industry need for this project, and would create re-work in the TOP and IRO Standards that are currently in-process. The industry must work diligently to eliminate such inefficiencies in the Process. The NERC BOT recently approved pursuing the Results/Performance Based standards development activity. Based on this recent decision, the BOT has signaled its intention to move any items from Standards and Requirements that dictate "capabilities" (as proposed), and focus on "outcome."
See the response to Question 1 above. In a Results/Performance Based standard this is not a vaild point. Without the necessary tools (whatever those have been determined to be), Standard Requirements will be violated. An IROL will be violated, failure to recover from a Reportable Event will result in a DCS violation, etc.
No
See the response to Question 1 above. In a Results/Performance Based standard this is not a valid point. Without the necessary tools (whatever those have been determined to be), Standard Requirements will be violated. An IROL will be violated, failure to recover from a Reportable Event will result in a DCS violation, etc.

See the response to Question 1 above.
Group
Hydro One Networks Inc.
Scott Vidler
Yes
No
Yes
Yes
Individual
Martin Bauer
US Bureau of Reclamation
No
The purpose of the SAR was to implement the issues not covered by Projects 2006-02 and 2007-03, namely the FERC Order 693 directive pertaining to IRO-002 and TOP-006. That being said the Commission clearly indicated that the standards need to be modified to require a "minimum set of tools that must be available to the reliability coordinator" to perform its functions. The SAR should be very clear on that point to avoid unnecessary complexity. Furthermore the Commission ordered that a provision was needed for minimum set of analytic tools [minimum capabilities] "that are necessary to enable operators to deal with real-time situations…" This was further clarified as "(1) includes a new requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System and (2) clarifies the meaning of "appropriate technical information" concerning protective relays." The language of the SAR needs to include this specific guidance.
No
The Commission was very clear that the modification it was requesting for TOP-006 could involve new capabilities for the Balancing Authority, the Transmission Operators and possibly the Reliability Coordinator.
Yes
No
The SAR needs to incorporate the language from Order 693. The scope should be limited to the modification of respective standards.
Group
SERC OC Standards Review Group
Jim Case
Yes
Yes
Some of the requirements (to have a certain capability or if we are forced there by FERC, a certain type of tool) best belong in certification. However, we agree that a requirement to have greater than a minimum certain 12 month-ending availability of an analytical capability and a requirement to have greater than a certain minimum quality of solution as measured on a 12 month-ending basis could better be addressed as a Reliability Standard. That is, the existence of a capability belongs in certification. Operational attributes of this capability belong in Reliability Standards. A demonstration of the functionality should be in the certification process, however once an entity is certified then compliance to performance metrics, availability parameters, etc could be in a standard. If an entity meets the performance metrics then obviously they must have the tools.
No
COM-002 R1 states "…voice and data links" shall be "…available for addressing a real-time emergency condition". The SDT should consider clarifying this point in relation to the performance

metrics, availability parameters, etc as outlined in this SAR.
No
Bullet 5 of the Detailed Description references: "…future state of the BES". The SDT needs to be cautious in defining what this means or remove that language altogether. The other bullets clearly spell out "Real-time" which defined by the NERC Glossary is "Present time as opposed to future time". Bullet 5 appears to contradict the other bullets in its timeframe scope. "The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Individual
Jon Kapitz
Xcel Energy
Yes
No
Given that there is no re-certification process, the proposed SAR should address the tools required by entities to address the real time monitoring issues.
Yes
Yes
Individual
Kasia Mihalchuk
Manitoba Hydro
Changing the proposed Standard Title to Real-time Reliability Monitoring and Analysis Capabilities from Real-time Tools does capture the context of the Standard better, but the SAR's purpose still does not shed enough light on what the SAR is trying to accomplish. Suggested change to Purpose: The new or revised standard(s) will establish the minimum (see note 1) requirements for the real time monitoring (see note 2), analysis (see note 3) and their procedural administration (see note 4) on the Interconnected Bulk Electric System for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations. Suggested change to Brief Description: The scope of the SAR is to establish the minimum requirements for alarming and telemetry and the administration procedures of System Analysis provided to System Operators and used to support Real-time System Operations. The SAR addresses availability parameters, performance studies (see note 5), and procedures for failure notification, maintenance coordination, and procedural changes. The intent is to describe 'what' needs to be done but not 'how' to do it. Using the statement "minimum requirements' should alleviate industry concerns about this requirement being too prescriptive and the statement makes the SAR more coincident with FERC Order 693 directive. NOTES 1. Minimum – this word is used to more closely comply with FERC order 693, paragraph 905. Also inserting "minimum" doesn't imply major change. 2. Real Time Monitoring – details specific function, whereas "functionally" is vague and open to interpretation. 3. Analysis – Another specific function is detailed, whereas "functionally" is vague and open to interpretation. 4. Procedural Administration – more clearly indicates that monitoring and analysis polices will be detailed in the SAR as opposed to "Change Management". 5. Metrics – prefer studies. Using the statement "minimum requirements' should alleviate industry concerns about this requirement being too prescriptive and the statement makes the SAR coincident with FERC Order 693 directive.
Yes
Though the introduction of a new standard is not welcome, this appears to be the only way to ensure measurable and enforceable goals.
Yes
As much as we desire NOT to see a new standard, by examining the SAR and related FERC Order 693, the following goals: Based on the SARS Detailed Description, the following goals are: • describe capability characteristics • availability parameters • performance metrics • failure notification • maintenance coordination • change management • independent process monitor (watchdog) • monitoring power system data in real time • exchanging power system date in real time and from

FERC 693 905 - RC has minimum set of tools 906 – Identify minimum capabilities and not tools (tools become obsolete) 1660 – Minimum set of analytical tools (not specific tools) would require modification of requirements from quite a few different Standards.
Yes
Very tangible details such as telemetry, alarming, Network Analysis terms were removed from the SAR and replaced with vague terms such as: • describe capability characteristics • availability parameters • performance metrics • failure notification • maintenance coordination • change management • independent process monitor (watchdog) • monitoring power system data in real time • exchanging power system date in real time If it wasn't for the SAR redline copy (that contained telemetry, alarming, Network Analysis) the above terminology would be difficult to assess. 1. Capability characteristics of what, analytical tools, alarms, telemetry, all these items? 2. Availability parameters of what, analytical tools, alarms, telemetry, all these items? 3. Failure notification of what, analytical tools, alarms, telemetry, all these items? 4. Maintenance coordination of what, analytical tools, alarms, telemetry, all these items? 5. Change Management (See note 4 in question 1) of what, analytical tools, alarms, telemetry, all these items? 6. Under which of the above SAR details could you assume FERC order 693 "minimum set of analytical tools" falls under? 7. What does "Independent process monitor (watchdog)" mean is that an analytical tool or is that an RC? 8. Exchanging and monitoring power system date in real time, isn't that covered in TOP-005 1.1, "Attachment 1 — TOP-005-1.1"?
Individual
Greg Rowland
Duke Energy
Yes
No
Yes
However the Standards Drafting Team must be careful not to duplicate existing requirements in other standards, and until we see a draft it's difficult to say there won't be any duplication. For example, the Detailed Description of the SAR has a bullet "Evaluating the impact of 'what if' events on the current or future state of the BES." This could duplicate TOP-002-2 Requirement R6 which states that "Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.
Yes
Group
NERC Standards Review Subcommittee
Carol Gerou
Yes
N/A
No
Wouldn't this be covered by NERC BOT approved PER-005-1 as a reliability related task?
Yes
N/A
Yes
N/A
Individual
Chris Scanlon
Exelon
Yes

Yes
Yes
Group
Dominion
Louis Slade
No
Despite SDTs response to comments concerning inclusion of Generator Operator, we remain unconvinced of the need to add this entity. In the Industry Need section the SDT cites the following, none of which indicates a need to include Generator Operators; Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations FERC Order 693 - paragraphs 905, 906 & 1660
No
Yes
Yes
Individual
Kathleen Goodman
ISO New England Inc
No
The current draft of the SAR indicates the applicability to be intended to extend to RCs, BAs, TOPs, and GOPs. If also indicates the industry need was identified through the August 14 Blackout report and references FERC Order 693. This is misleading, because: 1) The "tools" issues related to the August 14 Blackout were restricted to the TOP and RC functions and there was no indication that the BA or GOP tools were lacking in any respect. 2) FERC Order 693 stipulated (a) "ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator" and "The Commission approves TOP-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to TOP-006-1 through the Reliability Standards development process, as discussed below." As referenced in the "Related Standards" section, this endeavor is best suited under the responsibility of existing drafting teams working on the RC and TOP Standards sets. Or, in the alternative, as was commented in the first round of posting, these could be easily addressed through the Certification Process of the RC and TOP. We do not believe there is an industry need for this project and, to the contrary, would create re-work in the TOP and IRO Standards that are currently in-process. We must work diligently as an industry to eliminate such inefficiencies in the Process. Of final note, the NERC BOT recently approved the pursuing the Results/Performance Based standards development activity. Based on this recent decision, we believe the BOT has signaled their intent to move any from Standards and Requirements that dictate "capabilities" (as proposed) and focus on "outcome."
See answer to #1 above. Also, in a Results/Performance Based standards world, this is a moot point. If you do not have the necessary tools, whatever your company has determined that those may be, you will violation Standard Requirements. You will, for example, violate an IROL, fail to recover from a Reportable Event, etc.
No
See answer to #1 above. Also, in a Results/Performance Based standards world, this is a moot point. If you do not have the necessary tools, whatever your company has determined that those may be, you will violation Standard Requirements. You will, for example, violate an IROL, fail to recover from a Reportable Event, etc.
See answer to #1 above.
Individual
Roger Champagne
Hydro-Québec TransÉnergie (HQT)
No

The current draft of the SAR indicates the applicability to be intended to extend to RCs, BAs, TOPs, and GOPs. It also indicates the industry need was identified through the August 14 Blackout report and references FERC Order 693. This is misleading, because: 1) The "tools" issues related to the August 14 Blackout were restricted to the TOP and RC functions and there was no indication that the BA or GOP tools were lacking in any respect. 2) FERC Order 693 stipulated (a) "ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator" and "The Commission approves TOP-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to TOP-006-1 through the Reliability Standards development process, as discussed below." As referenced in the "Related Standards" section, this endeavor is best suited under the responsibility of existing drafting teams working on the RC and TOP Standards sets. Or, in the alternative, as was commented in the first round of posting, these could be easily addressed through the Certification Process of the RC and TOP. We do not believe there is an industry need for this project and, to the contrary, would create re-work in the TOP and IRO Standards that are currently in-process. We must work diligently as an industry to eliminate such inefficiencies in the Process. The NERC BOT recently approved pursuing the Results/Performance Based standards development activity. Based on this recent decision, we believe the BOT has signaled their intent to move any from Standards and Requirements that dictate "capabilities" (as proposed) and focus on "outcome."
See the response question 1 above. In a Results/Performance Based standards world, this is not a valid point. Without the necessary tools, whatever those have been determined to be, Standard Requirements will be violated. An IROL will be violated, failure to recover from a Reportable Event will result in a DCS violation, etc.
No
See the response to question 1 above. In a Results/Performance Based standards world, this is not a valid point. Without the necessary tools, whatever those have been determined to be, Standard Requirements will be violated. An IROL will be violated, failure to recover from a Reportable Event will result in a DCS violation, etc.
No
See the response to question 1 above.
Group
PacifiCorp
Sandra Shaffer
Yes
No
Yes
No
Individual
James H. Sorrels, Jr.
American Electric Power
Yes
AEP appreciates the SDT's efforts to re-align the SAR to focus on the "what" rather than the "how."
No
Given the limitations described, it seems appropriate to proceed with the standards development process to resolve these reliability issues as advocated by the SDT. AEP is hopeful that efforts will continue on the certification front to meet the reliability concerns expressed in this SAR as well. Ultimately, we believe that the NERC certification process of functional entities to ensure that the right tool set is in place and operating correctly is preferable to allowing, by administrative registration alone, to begin operating and then, afterwards, trying to invoke standards to address operating issues that could have been avoided up-front.
No
AEP believes that elements identified in the detailed description portion of the SAR are largely covered in the existing standards, including those shown below (Table 1). The roll-up of SAR

functions from SAR version 1 to a higher level descriptor in SAR version 2 does not seem to limit the relevance of all of the listed standards that AEP has researched. We are concerned that repetition of requirements across multiple standards may create ambiguity if alternative requirements or methods are defined from one to the other. The repetition also establishes the possibility of compounding violations for a single infraction. To the extent that new requirements are needed to address operational gaps, we believe that these should be made in the next revision of the applicable existing standards. TABLE I - Existing NERC Reliability Standards addressing Alarming, Telemetry, Network Analysis, Related Performance Metrics (Availability and Quality), and Processes and Procedures supporting Real-Time Tools (Change Mgt., Maintenance Coordination, and Failure Notification) : Alarming COM-001-1.1, does have some language related to the alarming of vital telecommunications facilities for voice and data. TOP-006-2 stress the importance of monitoring equipment to be used to 'alarm' or bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action. IRO-002-2, gives direction on the alarming management and awareness systems that need to be in place for the RC. Telemetry BAL-001-0, dealing with the ACE equation along with Control Performance Standards (CPS1 and CPS2) BAL-004-0, addressing Time Error Corrections BAL-005-0.1b, focuses on the telemetry components necessary for calculating the ACE equation BAL-006-1.1, tasks the Balancing Authorities to calculate and record hourly Inadvertent Interchange IRO-004-1, details the information that needs to be sent to the RC for reliability studies to be performed IRO-005-3, breaks down most of the parameters that a RC would need to receive for monitoring the BES TOP-002-2, highlights that changes in transmission facility status, along with ratings should be monitored and conveyed to the RC and BA TOP-005-2 is the Operational Reliability Information standard that lays out all of the data that needs to be updated at least every ten minutes TOP-006-2 is another standard focused on monitoring system conditions. VAR-001-1 also is offering details on what data should be pipelined back to the operating control centers from the BES. Network Analysis IRO-004-1, discusses the ability for the RC, TO, and BA to conduct next-day reliability analyses to ensure that the BES can be operated reliably. TOP-002-2, looks at the performance of current-day, next-day, and studies operational studies in conjunction with neighboring BA(s) and TO(s). TOP-002-2, also address the thermal and voltage contingency analysis that needs to be performed. IRO-002-2, details the analysis that needs to take place via state estimation and other visualization tools. Performance Metrics for Availability and Quality Availability BAL-005-0.1b, R8 looks at SCADA availability to gather data and calculate ACE. This requirement also addresses the availability of Frequency Metering equipment (99.95%). COM-001-1.1, stresses the diversity and redundancy of communication paths for the available exchange of Interconnection and operating information, internally and externally to AEP. EOP-008-0, emphasizes the development of a plan to ensure the monitoring and control of transmission, distribution and generation assets even with the loss of the Control Center. Quality BAL-005-0.1b, R17 breaks down the accuracy of the metering devices for time error and frequency measurements BAL-006-1.1, requires adjacent balancing authorities to have common megawatt-hour meters at the interconnection point. IRO-005-3, discusses the importance of operating to the most limiting element if there is a discrepancy between various entities monitoring the same facilities. TOP-006-2 generically states that sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions. Processes and Procedures supporting Real-Time Tools: Change Mgt., Maintenance Coordination, and Failure Notification Change Management FAC-009-1, obligates the communication to RC(s), PA(s), TP(s), and TO(s) for new facility ratings on the Bulk Electric System. TOP-002-2, implies that there should be a facility change notification system in place for neighboring entities to use uniform line identifiers when referring to interconnected facilities. BAL-004-0, addressing Time Error Corrections Maintenance Coordination FAC-009-1, it is implied that these changes will be applied to the real time computer model with alterations to facility ratings on the Bulk Electric System. TOP-002-2, talks about each BA and TO maintaining accurate computer models for analyzing and planning system operations. Failure Notification IRO-005-3, highlights the responsibility to identify significant issues with ACE that can attribute to other errors, such as frequency error and Time error. As the SDT has described, the directives in Order 693 relate to IRO-002 and TOP-006 and indicate a desire for a minimum set of capabilities. If the present SDTs for the referenced projects do not currently have these reliability issues in their scope, it would seem appropriate for NERC to slate these improvements for the next version of these respective standards.
Yes
Group

AECI System Operations
James Vermillion
Yes
No
Yes
Yes
Individual
Jason L. Marshall
Midwest ISO
No
The Midwest ISO believes that a basic set of tools should be prescribed in the Reliability Standards for Reliability Coordinators.
No
The Midwest ISO believes a basic set of tools should be required for Reliability Coordinators. We believe they should part of the Reliability Standards so they will be part of the three-year audit cycle to ensure that the Reliability Coordinators maintain this basic tool set.
Yes
Yes
Individual
Mark Ringhausen
ODEC
No
While better, more focus on performance based requirements needs to be included in the standard.
No
Certification is a process that says the entity has the capability to meet the requirments applicable to them, but this does not mean that the entity will meet the requirements. The two are different and need to be kept that way. One time certification is fine, the region could ask for re-certification if they find defeciencies with the entity in their performance.
No comment.
Group
E.ON U.S.
Brent Ingerigtson
Yes
Though generally supportive of the approach, E.ON U.S. believes it is incumbent upon the SDT to draft requirements that provide sufficient notice to registered entities of what it is they should or should not do to become or remain compliant.
Yes
A demonstration of the functionality should be in the certification process, however once an entity is certified then compliance to performance metrics, availability parameters, etc could be in a standard. If an entity meets the performance metrics then obviously they must have the tools.
Yes
COM-002 R1 states "…voice and data links" shall be "…available for addressing a real-time emergency condition". The SDT should consider clarifying this point in relation to the performance metrics, availability parameters, etc as outlined in this SAR.
No
Bullet 5 of the Detailed Description references "…future state of the BES". The SDT needs to be

cautious in defining what this means or remove that language altogether. The other bullets clearly spell out "Real-time" which defined by the NERC Glossary is "Present time as opposed to future time". Bullet 5 appears to contradict the other bullets in its timeframe.
Individual
James Sharpe
South Carolina Electric and Gas
Yes
No
No
BAL-005 R8, R14, and R16 define the BAs requirments for monitoring real-time data for the operation of AGC. The new standard should not confict with these requirements.
No
There are some terms used in the SAR that need to be clarified, such as "watch dog". Better define what is meant by "independent process monitor". Is the group specifying how the system should function or specific tool that should be used.
Group
FirstEnergy
Sam Ciccone
No
While we agree the SAR DT has improved the SAR, we suggest further improvement by revising the purpose statement (Pg. 2) as follows to ensure the scope is limited to aspects related to the reliability of the BES: "The new or revised standard(s) will establish requirements for the functionality, performance, and change management of Real-time Monitoring and Analysis capabilities for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable Bulk Electric System operation." In addition, the following bullet points under the detailed description (Pg. 3) should be revised as follows to ensure proper focus of the standard. • Monitoring Bulk Electric System reliability-related data in Real-time. • Exchanging Bulk Electric System reliability-related data in Real-time.
No
While we agree the changes proposed in this SAR are not suited to the organization certification process, we are unclear as to why the Project 2007-03 SDT feels this project cannot be combined with theirs. Part of their responsibility appears to be managing the rules for the use of the System Operator tools. This SAR proposes to require a set of tool capability and performance. It would seem logical to expect the team responsible for specifying the use of system operator tools would have the skill set to determine the tool set make up and the performance needed from to those tools to produce an outcome consistent with the reliability of the BES. If left as separate projects, a high degree of coordination seems necessary to ensure the tools required and the use of those tools are sufficiently covered by the standards.
Yes
No
See comments provided in item 1 above. Also, on Pg. 2 of the SAR it would be more helpful if it specifically stated the following regarding FERC directives: 1. "In Par. 905 of Order 693 '... the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe that this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. Further, as noted by Dominion, such a requirement promotes a more proactive approach to maintaining reliability'." 2. "In Par. 1660 of Order 693, FERC directed modifications to TOP-006-1 1660 '... related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System. In response to APPA that the inclusion of specific analytical tools is counterproductive because the tools will become obsolete, we note that we are not seeking specific analytical tools, but rather minimum capabilities'." Also, it should be noted that the SDTs currently working on IRO-

002 and TOP-006, Project 2006-06 and 2007-03, respectively, are proposing to retire both of these standards. Therefore, the eventual SDT for this Project 2009-02 will have to determine the appropriate standards to include new requirements for Real-time monitoring and analysis capabilities.
Group
Western Electricity Coordinating Council
Linda Perez
Yes
No
We agree that certification should be a one-time process and that the compliance audits of entities every 3 years should adequately address the issue of capabilities without recertification.
No
We believe the current requirements in the standards are adequate to address the basic capabilities required of the RCs. However, the requirements applicable to RCs are more specific in many cases than the requirements applicable to other entities.
No
We are not certain we understand the meaning of the reference to a watch dog. This functionality shall include an independent process monitor (e.g., watchdog). The IRO standards cover the items listed in the detailed description, so the STD should not be duplicative of the IRO standards.
Individual
Jeff Hackman
Ameren
No
While the new language partially allays the concern, it still does not differentiate that these capabilites are a collection of defense-in-depth capabilities and that no one capability is critical to BES reliability.
Yes
First of all, the team asserts in this question that FERC Order 693 requires the team to address "tool capability". Yet it disingenously has renamed itself to talk about capabilites and NOT tools. It therefore begs the question, "Why would this SAR be better to address 693's "tools". Just because recertification is not currently in the process does not mean it could not be added, especially in cases where fundamental qualifications change.
No
No
see general comment in 1
Individual
Jason Shaver
American Transmission Company
Yes
No
Yes
Yes
Individual
Richard Kafka
Pepco Holdings, Inc.
No
The SAR proposes to address an area that is already covered by the standards themselves. Current

NERC standards mandate performance compliance. There is no need to create a standard to also mandate how to achieve that level of perfomance. Further the GOP should not be considered as an applicable entity because the GOP has no monitoring or analysis obligations.
Yes
Performance based reliability standards will ensure compliance. There is no need for measuring the physical performance of the tools used to meet those reliability performance requirements.
No
See response to Q1 and Q2
Individual
Edward Davis
Entergy Services
Yes
Yes
Yes
Yes
Individual
Wayne Pourciau
Georgia System Operations Corporation
No
The change in words and the explanation given does not change what this is. This is a project to develop additional mandatory requirements for entities to follow when there are already to many existing requirements. There should be a separate certification process for obtaining and maintaining certification. This process should include capability requirements. Spending industry resource time on this capability SAR at this time takes away resources from the most important NERC project, the project to revise the entire set of standards to result in only the necessary risk-informed, performance-based requirements. Requiring specific capability is not prescribing what tool to use to achieve the capability. However, it is prescribing what capabilities to have and what performance, availability, and maintenance requirements to follow for these capabilities. That is still being prescriptive. A Reliability Standard requirement should be a requirement to provide for reliable operation of the bulk-power system including requirements for the operation of existing bulk-power system facilities and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system. It should not be a requirement to provide for reliable operation, functionality, performance, availability, and maintenance of a capability (a tool) used for reliable operation of the bulk-power system and facilities. The industry and the tool vendors should determine what tools and functionality are needed to provide for reliable operation of the bulk-power system in terms of their own system and the scope of their responsibilities and what is needed for reliable tools operation and maintenance. Capability requirements should not be in a mandatory reliability standard. The project to determine risk-informed, performance-based requirements should not include requirements for capabilities. See the response to no. 2 regarding a certification process.
Yes
Yes, the issues addressed in the proposed SAR belong in a certification process. Why, because there is no adequate certification process today, should a certification issue be turned into a Reliability Standard issue? Having certain capabilities is a certification issue and should be addressed by fixing the certification process. Certification processes should apply criteria to entities that have already been certified. Certification should not be a one time process. There should be a certification and re-certification process. There was no operational history associated with mandatory reliability standards before June 2007. Such an operational history is being built now. After developing and putting in place an adequate certification program, then there will be an operational history associated with certification and re-certification. Certification criteria that deal with real-time operations or data should be evaluated by a certification team to determine if the entity has

adequate functionality to be certified. Certification should not rely on the Compliance Monitoring and Enforcement Program (CMEP) to prove adequate functionality when there are violations of standards or on an on-going basis. There should be a separate certification (or capability verification) program to prove that. The issues raised by FERC should be addressed by first revamping all NERC requirements to risk-informed, performance-based requirements and developing a capability verification (certification) program. Then with a new slate of comprehensive, measurable, and auditable requirements and with a capability verification program, the original issues of FERC would be addressed. It is easy to perceive how having these things could eliminate the root problems and therefore the need to come up with solutions. That should satisfy and sustain a mandatory and enforceable status for those FERC directives. This SAR does not need to move forward to address the FERC directives.
No
The best use of NERC's and the industry's thinly stretched resources is to work on the project to revise the entire set of standards to result in only the necessary risk-informed, performance-based requirements. Then there should be no gap of requirements. The approach taken by the Standards Development Program, to not write new requirements that assess basic capabilities used to achieve performance measured through other requirements within the Reliability Standards, would result in no need for this SAR because all necessary performance (of the bulk power system) requirements would then be in the Reliability Standards. Rather than adding more requirements, NERC should eliminate unnecessary requirements to a number of important performance-based requirements. Resources are being stretched thinner and thinner. Resources spend time complying with the letter of unnecessary, poorly worded requirements rather than complying with the spirit of what should be required and the translation of that spirit into literal performance-based requirements. Much time is also spent reviewing, commenting, and voting on all of the other existing NERC projects. If it came to a choice of performing only the project to revise the standards to result in only the necessary risk-informed, performance-based requirements or performing all of the other projects in NERC's 3 year plan, it would do more good for reliability and for compliance enforcement to accomplish only that one performance-based project. In fact, rather than doing all of the projects, it would be best for the sake of the limited amount of resources to put a hold on most (if not all) of the other projects and to work only on this one comprehensive project. The "staffing" and content of the ongoing and existing projects should be reorganized to be merged into and organized around the comprehensive results-based project and not around the existing very many separate projects that sprang up at different times with different objectives and perspectives. Performing this project first would likely correct the issues or problems which lead to the creation of many of the existing projects. Many of the other projects could be cancelled.
No comment.
Group
Bonneville Power Administration
Denise Koehn
Yes
Additional Comments: Would be helpful if Directives were put into the Reference information. BPA supports having watchdog timers. BPA is uncertain about what wide area (Situational Awareness) is common to all TOP/BA that would be acceptable to all auditors. BPA would like clarity regarding what "procedure for failure notification" means (report to RC if link is down between TOP and RC or between station RTU and TOP ???) It appears that this SAR will add more documentation requirements.
No
Yes
Yes
Group
Public Service Enterprise Group Companies
Kenneth D. Brown
No
The SAR should be further clarified to specify that the standard should provide performance

standards rather than tools themselves. The SAR language still contains elements of "how," such as specifying audio and visual signals.
Yes
Yes, tools and tool capabilities are better handled within a certification process, that is, a certification that the entity has tools that are needed to meet the requirements of a standard. The certification process could be conducted initially and as a periodic re-certification if that is deemed necessary.
No
Monitoring is difficult to describe in a standard. The SAR has the potential to result in a standard that creates an undue administrative burden that is highly subjective, especially in the context of a compliance audit. Also, the subject matter of the SAR appears to be applicable to tasks necessarily performed by transmission operators but not necessary for generator operators. GOP should be eliminated from the applicable entities.
Individual
Dan Rochester
Independent Electricity System Operator
Yes
Yes
As expressed in our previous comments, we believe that these capability requirements are best stipulated in the Organization Certification Requirements. The absence of a re-certification process is not a convincing reason for not pursuing this alternative since: a. The requirements to continuously maintain or periodically demonstrate the capability can be added to the certification process; or b. A proposal can be made to develop a re-certification process or certificate maintenance process which in many commenters' view is needed not just for this set of requirements but also for other "capability" type of requirements. That said, we would agree that in the essence of time to meet Order 693's directives, developing a standard to house these requirements may be an acceptable interim approach before a workable certification process is developed, for so long as the requirements focus on the "what's" but not the "how's".
Yes
Yes
Group
IRC Standards Review Committee
Ben Li
No
The SAR indicates the applicability to be extended to RCs, BAs, TOPs, and GOPs. It also indicates the industry need was identified through the August 14 Blackout report and references FERC Order 693. This is misleading, because: 1) The "tools" issues related to the August 14 Blackout were restricted to the TOP and RC functions and there was no indication that the BA or GOP tools were lacking in any respect. 2) FERC Order 693 stipulated (a) "ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator" and "The Commission approves TOP-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to TOP-006-1 through the Reliability Standards development process, as discussed below." As referenced in the "Related Standards" section, this endeavor is best suited under the responsibility of existing drafting teams working on the RC and TOP Standards sets. Or, in the alternative, as was commented in the first round of posting, these could be easily addressed through the Certification Process of the RC and TOP. We believe there is an industry need for this project but the project should involve revising the TOP and IRO Standards that are currently in-process, or better still, adding the necessary requirements to the Organization Certification Requirements for these entities. If the industry should support the need to develop similar capability requirements for the Balancing Authority, where justified, then we would suggest that such requirements be added to the Organization Certification Requirements for the BA as well. We do not believe the GOP needs to acquire similar capabilities in view of its scope of operation

which we believe falls outside of the intent of the FERC Order.
As expressed in our previous comments, we believe that these capability requirements are best stipulated in the Organization Certification Requirements. The absence of a re-certification process is not a convincing reason for not pursuing this alternative since: a. The requirements to continuously maintain or periodically demonstrate the capability can be added to the certification process; or b. A proposal can be made to develop a re-certification process or certificate maintenance process which in many commenters' view is needed not just for this set of requirements but also for other "capability" type of requirements. That said, we would agree that in the essence of time to meet Order 693's directives, developing a standard to house these requirements may be an acceptable interim approach before a workable certification process is developed, for so long as the requirements focus on the "what's" but not the "how's". In addition, we suggest the SDT to present to the Standards Committee and the Compliance and Certification Committee our recommendation for putting these requirements into the Organization Certification Requirements, and to revisit the re-certification process to ensure periodic verification of the certified capability.
No
See comment under Q1 and Q2, above.

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Consideration of Comments on 2nd Draft of SAR for Real-time Reliability Monitoring and Analysis Capabilities (Project 2009-02)

The Real-time Reliability Monitoring Analysis Capabilities SAR Drafting Team thanks all commenters who submitted comments on the 2nd draft of the standards for Real-time Reliability Monitoring and Analysis Capabilities (Project 2009-02). These standards were posted for a 30-day public comment period from January 19, 2010 through February 18, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 30 sets of comments, including comments from more than 80 different people from over 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Project2009-02_Real-Time_Monitoring_Analysis_Capabilities.html

The SAR DT has made a few clarifying changes to the text of the SAR in response to industry comments and now feels that the project is ready for approval by the Standards Committee to move forward to the standards development stage.

Several entities indicated that the proposed project does not support the "results-based" approach to developing standards and the SAR DT disagrees. The report generated by the Results-based Ad Hoc Team includes the following description of the types of requirements recommended for results-based standards:

> To achieve an adequate level of reliability, the team recommended a blended approach be used comprising of three types of requirements:
>
> **Performance-based** — defines a particular reliability objective or outcome to be achieved. In its simplest form, a performance-based standard has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome*?
>
> **Risk-based** — preventive requirements to reduce the risks of failure to acceptable levels. A risk-based reliability standard should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
>
> **Competency-based** — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions.

The proposed requirements are "Competency-based" as they define a set of capabilities needed to support reliable operations.

Some stakeholders are still stating that the items cited in the SAR should be part of a revised certification process accompanied by a new re-certification process. The SAR DT has no control over the certification/re-certification process and is working under the existing rules and procedures to fill a reliability gap.

Several comments were raised on the applicability of the Generator Operator. The Generator Operator is included here because it owns reliability data that is essential to the Transmission Operators and Balancing Authorities and the quality of that data is of concern. The focus on capabilities is different for the various reliability entities and the eventual SDT will need to define that focus. The SAR DT continues to believe that the eventual SDT needs to have the flexibility to include or not include the Generator Operator.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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, 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.

Index to Questions, Comments, and Responses

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.	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.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hdro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Brian D. Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	David Kiguel	Hydro One Networks Inc.	NPCC	1
12.	Michael R. Lombardi	Northeast Utilities	NPCC	1
13.	Randy MacDonald	New Brunswick System Operator	NPCC	2
14.	Greg Mason	Dynegy Generation	NPCC	5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
21.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
22.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jim Case	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chad Randall	E.ON.US		1, 3, 5
2.	Gerald Beckerle	Ameren		1, 3
3.	Randy Castello	Mississippi Power		1, 3, 5
4.	Robert Thomasson	Big Rivers		1, 3, 5, 9
5.	John Troha	SERC		10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Carol Gerou	NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck Lawrence	American Transmission Company	MRO	1
2.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
3.	Terry Bilke	Midwest ISO Inc.	MRO	2
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
8.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	11. Terry Harbour		MidAmerican Energy Company	MRO					1, 3, 5, 6				
4.	Group	Louis Slade	Dominion	X		X		X	X				
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
	1. Jalal Babik			RFC					3, 5, 6				
	2. Mike Garton			MRO					3, 5, 6				
5.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
	1. Dave Folk		FE	RFC					1, 3, 4, 5, 6				
	2. Doug Hohlbaugh		FE	RFC					1, 3, 4, 5, 6				
6.	Group	Linda Perez	Western Electricity Coordinating Council										X
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
	1. Steve Rueckert		WECC	WECC					10				
7.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
	1. Jim Burns		Transmission Technical Operations	WECC					1				
8.	Group	Kenneth D. Brown	Public Service Enterprise Group Companies	X		X		X	X				
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
	1. Jeff Mueller		PSE&G	RFC					1, 3				
	2. Ken Petroff		PSEG Nuclear	RFC					5				
	3. Jim Hebson		PSEG ER&T	ERCOT					5, 6				
	4. Dave Murray		PSEG Connecticut	NPCC					5				
9.	Group	Ben Li	IRC Standards Review Committee		X								
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
	1. Patrick Brown		PJM	RFC					2				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
2.	Charles Yeung	SPP	SPP					2					
3.	James Castle	NYISO	NPCC					2					
4.	Mark Thompson	AESO	WECC					2					
5.	Matt Goldberg	ISO-NE	NPCC					2					
6.	Lourdes Estrada-Salinero	CAISO	WECC					2					
7.	Steve Myers	ERCOT	ERCOT					2					
10.	Individual	Scott Vidler	Hydro One Networks Inc.	X									
11.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
12.	Individual	James Vermillion	AECI System Operations	X		X		X					
13.	Individual	Brent Ingerigtson	E.ON U.S.	X		X		X	X				
14.	Individual	Martin Bauer	US Bureau of Reclamation					X					
15.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
16.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
17.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
18.	Individual	Chris Scanlon	Exelon	X		X		X	X				
19.	Individual	Kathleen Goodman	ISO New England Inc		X								
20.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
21.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
22.	Individual	Jason L. Marshall	Midwest ISO		X								

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	Mark Ringhausen	ODEC			X	X	X					
24.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X				
25.	Individual	Jeff Hackman	Ameren	X									
26.	Individual	Jason Shaver	American Transmission Company	X									
27.	Individual	Richard Kafka	Pepco Holdings, Inc.	X		X		X	X				
28.	Individual	Edward Davis	Entergy Services	X		X		X	X				
29.	Individual	Wayne Pourciau	Georgia System Operations Corporation			X	X						
30.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. The Real-time Reliability Monitoring and Analysis Capabilities SAR DT has attempted to clarify the wording of the SAR to show that this SAR is focused on functionality and not on specific tools. In other words, this SAR addresses 'what' vs. 'how'. Do you agree that the revised SAR adequately allays industry concerns on being too prescriptive as to how the functionality will be addressed? If not, please provide recommended wording changes.

Summary Consideration: A majority of the commenters agree with the SAR DT's approach.

The SAR DT has made slight clarifying changes to the Purpose statement and the Detailed Description based on industry comments.

There were several commenters who are still expressing the opinion that certification/re-certification is the correct method to use. The SAR DT has no control over the certification/re-certification process and is working under the existing rules and procedures to fill a reliability gap.

The SAR DT does not see any point of conflict between the proposed results-based reliability standards effort and the proposed content of any eventual standard(s) or changes to existing standard(s) that this SAR might generate. Indeed, the SAR DT believes that the SAR directly addresses the competency element of the proposed results-based reliability standard effort.

Several comments were raised on the applicability of the Generator Operator. The Generator Operator is included here because it owns reliability data that is essential to the Transmission Operators and Balancing Authorities and the quality of that data is of concern. The focus on capabilities is different for the various reliability entities and the eventual SDT will need to define that focus. The SAR DT continues to believe that the eventual SDT needs to have the flexibility to include or not include the Generator Operator.

Purpose statement: The new or revised standard(s) will establish requirements for the functionality, performance, and maintenance of Real-time Monitoring and Analysis capabilities for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations.

Detailed description: Develop or revise standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, failure notification, and maintenance (vetted by the industry through the Reliability Standards comment process) of functionality for:

- Monitoring power System data in Real-time.
- Exchanging power System data in Real-time.
- Alerting System Operators in Real-time to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an independent process monitor.
- Determining the current state of the BES.

- Evaluating the impact of 'what if' events on the current state of the BES.

Organization	Yes or No	Question 1 Comment
Manitoba Hydro		Changing the proposed Standard Title to Real-time Reliability Monitoring and Analysis Capabilities from Real-time Tools does capture the context of the Standard better, but the SAR's purpose still does not shed enough light on what the SAR is trying to accomplish. Suggested change to Purpose: The new or revised standard(s) will establish the minimum (see note 1) requirements for the real time monitoring (see note 2), analysis (see note 3) and their procedural administration (see note 4) on the Interconnected Bulk Electric System for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations. Suggested change to Brief Description: The scope of the SAR is to establish the minimum requirements for alarming and telemetry and the administration procedures of System Analysis provided to System Operators and used to support Real-time System Operations. The SAR addresses availability parameters, performance studies (see note 5), and procedures for failure notification, maintenance coordination, and procedural changes. The intent is to describe 'what' needs to be done but not 'how' to do it. Using the statement "minimum requirements' should alleviate industry concerns about this requirement being too prescriptive and the statement makes the SAR more coincident with FERC Order 693 directive. NOTES 1. Minimum - this word is used to more closely comply with FERC order 693, paragraph 905. Also inserting "minimum" doesn't imply major change. 2. Real Time Monitoring - details specific function, whereas "functionally" is vague and open to interpretation. 3. Analysis - Another specific function is detailed, whereas "functionally" is vague and open to interpretation. 4. Procedural Administration - more clearly indicates that monitoring and analysis polices will be detailed in the SAR as opposed to "Change Management". 5. Metrics - prefer studies. Using the statement "minimum requirements' should alleviate industry concerns about this requirement being too prescriptive and the statement makes the SAR coincident with FERC Order 693 directive.
Response: The SAR DT has made a change to the Purpose statement based on your comment and those of others but does not believe that a change to		

Organization	Yes or No	Question 1 Comment
'procedural administration' is the right phrasing or in line with the new results-based standards effort. 'Minimum' was not utilized as it is often interpreted to mean a least common denominator approach. The SAR DT has deleted 'change management' as suggested and replaced it with 'maintenance' which is what the intent of the statement was. **Purpose statement**: The new or revised standard(s) will establish requirements for the functionality, performance, and maintenance of Real-time Monitoring and Analysis capabilities for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations. The SAR DT believes that 'monitoring and analysis' is more appropriate for the SAR as opposed to 'alarming and telemetry'. The SAR DT does not believe that 'administration procedures' or 'procedural changes' is the right phrasing or in line with the new results-based standards effort. 'Minimum' was not utilized as it implies a least common denominator approach which is not allowed. The SAR DT believes that 'metrics' is the correct terminology and in line with results-based standards. No change made.		
Dominion	No	Despite SDTs response to comments concerning inclusion of Generator Operator, we remain unconvinced of the need to add this entity. In the Industry Need section the SDT cites the following, none of which indicates a need to include Generator Operators; Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations FERC Order 693 - paragraphs 905, 906 & 1660
Response: The Generator Operator is included here because it owns reliability data that is essential to the Transmission Operators and Balancing Authorities and the quality of that data is of concern. The focus on capabilities is different for the various reliability entities and the eventual SDT will need to define that focus. For example, the Generator Operator would not be expected to perform network analysis. The SAR DT continues to believe that the eventual SDT needs to have the flexibility to include or not include the Generator Operator. No change made.		
Georgia System Operations Corporation	No	The change in words and the explanation given does not change what this is. This is a project to develop additional mandatory requirements for entities to follow when there are already to many existing requirements. There should be a separate certification process for obtaining and maintaining certification. This process should include capability requirements. Spending industry resource time on this capability SAR at this time takes away resources from the most important NERC project, the project to revise the entire set of standards to result in only the necessary risk-informed, performance-based requirements. Requiring specific capability is not prescribing what tool to use to achieve the capability. However, it is prescribing what capabilities to have and what performance, availability, and maintenance requirements to follow for these capabilities. That is still being prescriptive. A Reliability Standard requirement should be a requirement to provide for reliable operation of the bulk-power system including requirements for the operation of existing bulk-power system facilities and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system. It should not be a requirement to provide for reliable operation, functionality, performance, availability, and maintenance of a capability (a tool) used for reliable

Organization	Yes or No	Question 1 Comment
		operation of the bulk-power system and facilities. The industry and the tool vendors should determine what tools and functionality are needed to provide for reliable operation of the bulk-power system in terms of their own system and the scope of their responsibilities and what is needed for reliable tools operation and maintenance. Capability requirements should not be in a mandatory reliability standard. The project to determine risk-informed, performance-based requirements should not include requirements for capabilities. See the response to no. 2 regarding a certification process.
Response: The existing certification process (which is standard-driven) or any future re-certification effort is outside the scope of the SAR DT. The SAR DT can only react to the certification/re-certification issue as it exists today. The SAR DT believes that this indicates that a standard(s) or changes to existing standard(s) is required to achieve desired reliability objectives. No change made. This SAR does not prevent an entity or its vendor from selecting a particular tool to use to provide the necessary capabilities. No change made. The SAR DT does not see any point of conflict between the proposed results-based reliability standards effort and the proposed content of any eventual standard(s) or changes to existing standard(s) that this SAR might generate. Indeed, the SAR DT believes that the SAR directly addresses the competency element of the proposed results-based reliability standard effort. No change made. Please see response to #2.		
Hydro-Québec TransEnergie (HQT)	No	The current draft of the SAR indicates the applicability to be intended to extend to RCs, BAs, TOPs, and GOPs. It also indicates the industry need was identified through the August 14 Blackout report and references FERC Order 693. This is misleading, because: 1) The “tools” issues related to the August 14 Blackout were restricted to the TOP and RC functions and there was no indication that the BA or GOP tools were lacking in any respect. 2) FERC Order 693 stipulated (a) “ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator” and “The Commission approves TOP-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to TOP-006-1 through the Reliability Standards development process, as discussed below.” As referenced in the “Related Standards” section, this endeavor is best suited under the responsibility of existing drafting teams working on the RC and TOP Standards sets. Or, in the alternative, as was commented in the first round of posting, these could be easily addressed

Organization	Yes or No	Question 1 Comment
		through the Certification Process of the RC and TOP. We do not believe there is an industry need for this project and, to the contrary, would create re-work in the TOP and IRO Standards that are currently in-process. We must work diligently as an industry to eliminate such inefficiencies in the Process. The NERC BOT recently approved pursuing the Results/Performance Based standards development activity. Based on this recent decision, we believe the BOT has signaled their intent to move any from Standards and Requirements that dictate “capabilities” (as proposed) and focus on “outcome.”
ISO New England Inc	No	The current draft of the SAR indicates the applicability to be intended to extend to RCs, BAs, TOPs, and GOPs. If also indicates the industry need was identified through the August 14 Blackout report and references FERC Order 693. This is misleading, because: 1) The “tools” issues related to the August 14 Blackout were restricted to the TOP and RC functions and there was no indication that the BA or GOP tools were lacking in any respect. 2) FERC Order 693 stipulated (a) “ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator” and “The Commission approves TOP-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to TOP-006-1 through the Reliability Standards development process, as discussed below.” As referenced in the “Related Standards” section, this endeavor is best suited under the responsibility of existing drafting teams working on the RC and TOP Standards sets. Or, in the alternative, as was commented in the first round of posting, these could be easily addressed through the Certification Process of the RC and TOP. We do not believe there is an industry need for this project and, to the contrary, would create re-work in the TOP and IRO Standards that are currently in-process. We must work diligently as an industry to eliminate such inefficiencies in the Process. Of final note, the NERC BOT recently approved the pursuing the Results/Performance Based standards development activity. Based on this recent decision, we believe the BOT has signaled their intent to move any from Standards and Requirements that dictate “capabilities” (as proposed) and focus on “outcome.”
Northeast Power Coordinating Council	No	The current draft of the SAR indicates the applicability to be intended to extend to RCs, BAs, TOPs, and GOPs. It also indicates the industry need was identified through the August 14 Blackout report and references FERC Order 693. This is misleading because: 1) The “tools” issues related to the August 14 Blackout were restricted to the TOP and RC functions and there

Organization	Yes or No	Question 1 Comment
		was no indication that the BA or GOP tools were lacking in any respect. 2) FERC Order 693 stipulated (a) “ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator” and “The Commission approves TOP-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to TOP-006-1 through the Reliability Standards development process, as discussed below.” As referenced in the “Related Standards” section, this endeavor is best suited under the responsibility of existing drafting teams working on the RC and TOP Standards sets. Or, in the alternative, as was commented in the first round of posting, these could be easily addressed through the Certification Process of the RC and TOP. There isn't an industry need for this project, and would create re-work in the TOP and IRO Standards that are currently in-process. The industry must work diligently to eliminate such inefficiencies in the Process. The NERC BOT recently approved pursuing the Results/Performance Based standards development activity. Based on this recent decision, the BOT has signaled its intention to move any items from Standards and Requirements that dictate “capabilities” (as proposed), and focus on “outcome.”
Response: Recommendation 22 of the Blackout Report specifically cited the Reliability Coordinator and operators. The use of the term operators brings in the other entities cited in the SAR. No change made. As pointed out in the first posting comment response, the SDTs working on the revisions of the IRO (Project 2006-06) & TOP (Project 2007-03) standards disagree with your position as stated in the most recent project implementation plans. They have passed on the capability related requirements to this SAR DT. No change made. The existing certification process (which is standard-driven) or any future re-certification effort is outside the scope of the SAR DT. The SAR DT can only react to the certification/re-certification issue as it exists today. The SAR DT believes that this indicates that a standard(s) or changes to existing standard(s) is required to achieve desired reliability objectives. No change made. The SAR DT does not see any point of conflict between the proposed results-based reliability standards effort and the proposed content of any eventual standard(s) or changes to existing standard(s) that this SAR might generate. Indeed, the SAR DT believes that the SAR directly addresses the competency element of the proposed results-based reliability standard effort. No change made.		
IRC Standards Review Committee	No	The SAR indicates the applicability to be extended to RCs, BAs, TOPs, and GOPs. It also indicates the industry need was identified through the August 14 Blackout report and references FERC Order 693. This is misleading, because: 1) The “tools” issues related to the August 14 Blackout were restricted to the TOP and RC functions and there

Organization	Yes or No	Question 1 Comment
		was no indication that the BA or GOP tools were lacking in any respect. 2) FERC Order 693 stipulated (a) “ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator” and “The Commission approves TOP-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to TOP-006-1 through the Reliability Standards development process, as discussed below.” As referenced in the “Related Standards” section, this endeavor is best suited under the responsibility of existing drafting teams working on the RC and TOP Standards sets. Or, in the alternative, as was commented in the first round of posting, these could be easily addressed through the Certification Process of the RC and TOP. We believe there is an industry need for this project but the project should involve revising the TOP and IRO Standards that are currently in-process, or better still, adding the necessary requirements to the Organization Certification Requirements for these entities. If the industry should support the need to develop similar capability requirements for the Balancing Authority, where justified, then we would suggest that such requirements be added to the Organization Certification Requirements for the BA as well. We do not believe the GOP needs to acquire similar capabilities in view of its scope of operation which we believe falls outside of the intent of the FERC Order.
Response: Recommendation 22 of the Blackout Report specifically cited the Reliability Coordinator and operators. The use of the term operators brings in the other entities cited in the SAR. No change made. As pointed out in the first posting comment response, the SDT’s working on the revisions of the IRO (Project 2006-06) & TOP (Project 2007-03) standards disagree with your position as stated in the most recent project implementation plans. They have passed on the capability related requirements to this SAR DT. No change made. The existing certification process (which is standard-driven) or any future re-certification effort is outside the scope of the SAR DT. The SAR DT can only react to the certification/re-certification issue as it exists today. The SAR DT believes that this indicates that a standard(s) or changes to existing standard(s) is required to achieve desired reliability objectives. No change made. The Generator Operator is included here because it owns reliability data that is essential to the Transmission Operators and Balancing Authorities and the quality of that data is of concern. The focus on capabilities is different for the various reliability entities and the eventual SDT will need to define that focus. For example, the Generator Operator would not be expected to perform network analysis. The SAR DT continues to believe that the eventual SDT needs to have the flexibility to include or not include the Generator Operator. No change made.		
Midwest ISO	No	The Midwest ISO believes that a basic set of tools should be prescribed in the Reliability Standards for

Organization	Yes or No	Question 1 Comment
		Reliability Coordinators.
Response: FERC Order 693 specifically cites minimum capabilities for Reliability Coordinators in paragraph 1660 as opposed to a set of tools. The SAR DT agrees with the position espoused in Order 693 and has emphasized functionality accordingly. No change made.		
US Bureau of Reclamation	No	The purpose of the SAR was to implement the issues not covered by Projects 2006-02 and 2007-03, namely the FERC Order 693 directive pertaining to IRO-002 and TOP-006. That being said the Commission clearly indicated that the standards need to be modified to require a “minimum set of tools that must be available to the reliability coordinator” to perform its functions. The SAR should be very clear on that point to avoid unnecessary complexity. Furthermore the Commission ordered that a provision was needed for minimum set of analytic tools [minimum capabilities] “that are necessary to enable operators to deal with real-time situations...” This was further clarified as “(1) includes a new requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System and (2) clarifies the meaning of “appropriate technical information” concerning protective relays.” The language of the SAR needs to include this specific guidance.
Response: The SAR DT does not agree with the commenter’s statement on the Purpose of the SAR. The Purpose as stated in the SAR goes beyond that stated by the commenter by describing what the standard action will achieve in support of bulk power system reliability: “The new or revised standard(s) will establish requirements for the functionality, performance, and change management of Real-time capabilities for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations.” No change made. FERC Order 693 specifically cites minimum capabilities in paragraph 1660 as opposed to a set of tools. The SAR DT agrees with the position espoused in Order 693 and has emphasized functionality accordingly. No change made. “Appropriate technical information” for protective relays is a FERC comment on TOP-006 and is not pertinent to this SAR. No change made.		
Pepco Holdings, Inc.	No	The SAR proposes to address an area that is already covered by the standards themselves. Current NERC standards mandate performance compliance. There is no need to create a standard to also mandate how to achieve that level of performance. Further the GOP should not be considered as an applicable entity because the GOP has no monitoring or analysis obligations.
Response: The SAR DT believes that the current standards do not address all levels of needed performance hence the effort to fill a reliability gap with this SAR. The SAR addresses items not presently covered in any existing or proposed reliability standard. The SAR DT envisions that standards developed or revised as a result of this SAR will address reliability gaps in terms of performance, risk, and competency. No change made.		

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The Generator Operator is included here because it owns reliability data that is essential to the Transmission Operators and Balancing Authorities and the quality of that data is of concern. The focus on capabilities is different for the various reliability entities and the eventual SDT will need to define that focus. For example, the Generator Operator would not be expected to perform network analysis. The SAR DT continues to believe that the eventual SDT needs to have the flexibility to include or not include the Generator Operator. No change made.		
Public Service Enterprise Group Companies	No	The SAR should be further clarified to specify that the standard should provide performance standards rather than tools themselves. The SAR language still contains elements of "how," such as specifying audio and visual signals.
Response: The SAR DT has changed the wording in the 3rd bullet of the Detailed Description to accommodate your concerns. **Detailed description**: Develop or revise standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, failure notification, and maintenance (vetted by the industry through the Reliability Standards comment process)of functionality for: • Monitoring power System data in Real-time. • Exchanging power System data in Real-time. • Alerting System Operators in Real-time to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an independent process monitor. • Determining the current state of the BES. • Evaluating the impact of 'what if' events on the current state of the BES.		
ODEC	No	While better, more focus on performance based requirements needs to be included in the standard.
Response: This is a SAR and not a standard. There are no requirements at this point in time, just a reference for the future SDT. If this SAR is approved by the Standards Committee, it would move forward as a results-based standards effort. No change made.		
Ameren	No	While the new language partially allays the concern, it still does not differentiate that these capabilites are a collection of defense-in-depth capabilities and that no one capability is critical to BES reliability.
Response: This SAR deals with capabilities and concepts and does not attempt to define criticality. No change made.		
FirstEnergy	No	While we agree the SAR DT has improved the SAR, we suggest further improvement by revising the purpose statement (Pg. 2) as follows to ensure the scope is limited to aspects related to the reliability of the BES: "The new or revised standard(s) will establish requirements for the functionality, performance, and change management of Real-time Monitoring and Analysis capabilities for Reliability Coordinators, Transmission

Organization	Yes or No	Question 1 Comment
		Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable Bulk Electric System operation. "In addition, the following bullet points under the detailed description (Pg. 3) should be revised as follows to ensure proper focus of the standard. o Monitoring Bulk Electric System reliability-related data in Real-time. o Exchanging Bulk Electric System reliability-related data in Real-time.
Response: The SAR DT has added the suggested wording to the Purpose statement as it lines up the purpose of the SAR with the name of the project. **Purpose statement**: The new or revised standard(s) will establish requirements for the functionality, performance, and maintenance of Real-time Monitoring and Analysis capabilities for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations. The SAR DT believes that the bullets need to be read in context with the lead-in paragraph. Once that is done, the changes suggested are not necessary as it should be clear that the SAR is not citing what data needs to be supplied but the performance characteristics of the functions employed. No change made.		
Bonneville Power Administration	Yes	Additional Comments: Would be helpful if Directives were put into the Reference information. BPA supports having watchdog timers. BPA is uncertain about what wide area (Situational Awareness) is common to all TOP/BA that would be acceptable to all auditors. BPA would like clarity regarding what "procedure for failure notification" means (report to RC if link is down between TOP and RC or between station RTU and TOP ???) It appears that this SAR will add more documentation requirements.
Response: The SAR DT has included the paragraph numbers of the pertinent paragraphs in Order 693 and feels that this is sufficient as no other commenters have cited this as a problem. No change made. The SAR DT thanks you for your comment, however several entities objected to use of the term “watchdog” and this was removed from the revised SAR. The focus on capabilities such as situational awareness is different for the various reliability entities and the eventual SDT will need to define that focus. No change made. The SAR DT intended failure notification to mean something local to the affected entity, e.g., notification that a particular capability is not working as intended. No change made. There is almost certainly going to be some documentation requirements in the eventual standard(s) or revisions although the movement to results-based		

Organization	Yes or No	Question 1 Comment
standards should minimize this. However, the SAR DT has deleted the words '… procedures for…' in the failure notification phrasing as the intent is not a documented procedure but a notification. **Detailed description**: Develop or revise standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, failure notification, and maintenance (vetted by the industry through the Reliability Standards comment process)of functionality for: • Monitoring power System data in Real-time. • Exchanging power System data in Real-time. • Alerting System Operators in Real-time to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an independent process monitor. • Determining the current state of the BES. • Evaluating the impact of 'what if' events on the current state of the BES.		
E.ON U.S.	Yes	Though generally supportive of the approach, E.ON U.S. believes it is incumbent upon the SDT to draft requirements that provide sufficient notice to registered entities of what it is they should or should not do to become or remain compliant.
Response: This is still a SAR and the eventual SDT will take up the implementation plan for any new or revised standard(s). A sufficient lead time with stakeholder input would be part of their considerations. No change made.		
AECI System Operations	Yes	
American Transmission Company	Yes	
Duke Energy	Yes	
Entergy Services	Yes	
Exelon	Yes	
Hydro One Networks Inc.	Yes	
Independent Electricity System	Yes	

Organization	Yes or No	Question 1 Comment
Operator		
PacifiCorp	Yes	
SERC OC Standards Review Group	Yes	
South Carolina Electric and Gas	Yes	
Western Electricity Coordinating Council	Yes	
Xcel Energy	Yes	
American Electric Power	Yes	AEP appreciates the SDT's efforts to re-align the SAR to focus on the "what" rather than the "how."
NERC Standards Review Subcommittee	Yes	N/A
Response: Thank you for your support.		

2. In the first set of questions, several entities suggested that this functionality should and could be handled through certification. The SAR DT has researched the issue and has compiled the following information:

Certification is a one time process. New certification criteria do not apply to entities that have already been certified. There is no re-certification process nor are there any plans that the SAR DT is aware of to expand the certification process to include re-certification. Certification only proves that an entity had the functionality at a single point in time. There is no operational history associated with certification; therefore, certification criteria that deal with Real-time operations or data are only evaluated by the certification team to determine if the entity has adequate functionality to go operational. Certification relies on the Compliance Monitoring and Enforcement Program (CMEP) to prove compliance for this functionality on an on-going basis. However, CMEP can only evaluate compliance to requirements defined in the Reliability Standards. Therefore, the SAR is necessary to allow the creation of standard requirements to address the issues raised in the SAR so they will be evaluated by CMEP.

Furthermore, there are 2 directives in FERC Order 693 relating to tool capability that need to be addressed. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC. It is difficult to perceive how any additions or changes to the certification process could come up with a solution that would satisfy and sustain a mandatory and enforceable status for those directives. Therefore, this SAR needs to move forward or the existing projects need to take back the responsibility for addressing the directives.

Given this information, do you believe that the issues addressed in the proposed SAR belong in the certification process? If you respond 'Yes', please provide details as to how the goals of the proposed SAR (including the Order 693 directives) could be accomplished within the certification process given that there is no re-certification process to ensure that the goals of the proposed SAR will be met by all applicable entities including those already certified.

Summary Consideration: The majority of commenters agreed with the SAR DT's position. No changes were made to the SAR based on comments to this question.

There are a few commenters still suggesting that certification can be changed to accommodate the types of issues raised in the SAR. Those commenters have been directed to make their suggestions for changes to the certification process and/or institution of a re-certification process to the proper forum.

Organization	Yes or No	Question 2 Comment
IRC Standards Review Committee		As expressed in our previous comments, we believe that these capability requirements are best stipulated in the Organization Certification Requirements. The absence of a re-certification process is not a convincing

Organization	Yes or No	Question 2 Comment
		reason for not pursuing this alternative since: a. The requirements to continuously maintain or periodically demonstrate the capability can be added to the certification process; or b. A proposal can be made to develop a re-certification process or certificate maintenance process which in many commenters' view is needed not just for this set of requirements but also for other "capability" type of requirements. That said, we would agree that in the essence of time to meet Order 693's directives, developing a standard to house these requirements may be an acceptable interim approach before a workable certification process is developed, for so long as the requirements focus on the "what's" but not the "how's". In addition, we suggest the SDT to present to the Standards Committee and the Compliance and Certification Committee our recommendation for putting these requirements into the Organization Certification Requirements, and to revisit the re-certification process to ensure periodic verification of the certified capability.
Response: A standard can always be deleted if future changes to certification would make the requirements moot. It is outside the scope of the SAR DT to suggest changes to the certification process. Nor is it a Standards Committee item. In order to make the arguments for certification heard in the proper forum, industry representatives should forward the changes proposed to the NERC Compliance and Certification Committee. The SAR DT appreciates the support indicated for proceeding with the standards effort at this time.		
Independent Electricity System Operator	Yes	As expressed in our previous comments, we believe that these capability requirements are best stipulated in the Organization Certification Requirements. The absence of a re-certification process is not a convincing reason for not pursuing this alternative since: a. The requirements to continuously maintain or periodically demonstrate the capability can be added to the certification process; or b. A proposal can be made to develop a re-certification process or certificate maintenance process which in many commenters' view is needed not just for this set of requirements but also for other "capability" type of requirements. That said, we would agree that in the essence of time to meet Order 693's directives, developing a standard to house these requirements may be an acceptable interim approach before a workable certification process is developed, for so long as the requirements focus on the "what's" but not the "how's".
Response: A standard can always be deleted if future changes to certification would make the requirements moot. The SAR DT appreciates the support indicated for proceeding with the standards effort at this time. No change made.		

Organization	Yes or No	Question 2 Comment
ISO New England Inc		See answer to #1 above. Also, in a Results/Performance Based standards world, this is a moot point. If you do not have the necessary tools, whatever your company has determined that those may be, you will violation Standard Requirements. You will, for example, violate an IROL, fail to recover from a Reportable Event, etc.
Hydro-Québec TransEnergie (HQT)		See the response question 1 above. In a Results/Performance Based standards world, this is not a valid point. Without the necessary tools, whatever those have been determined to be, Standard Requirements will be violated. An IROL will be violated, failure to recover from a Reportable Event will result in a DCS violation, etc.
Northeast Power Coordinating Council		See the response to Question 1 above. In a Results/Performance Based standard this is not a vaild point. Without the necessary tools (whatever those have been determined to be), Standard Requirements will be violated. An IROL will be violated, failure to recover from a Reportable Event will result in a DCS violation, etc.
Response: See response to #1 above. The SAR DT does not see any point of conflict between the proposed results-based reliability standards effort and the proposed content of any eventual standard(s) or changes to existing standard(s) that this SAR might generate. Indeed, the SAR DT believes that the SAR directly addresses the risk-based element of the proposed results-based reliability standard effort. In the presentation to the NERC Board of Trustees (Proposal to Develop Results-Based Reliability Standards), the following example was quoted: “The analogy in airline safety would be a performance based requirement to avoid plane crashes. The cost of failure is too high to rely solely on enforcing compliance after such a failure. Like airline safety, bulk power system reliability requires additional, preventive requirements to reduce the risks of failure to acceptable tolerance levels.” No change made.		
AECI System Operations	No	
American Transmission Company	No	
Bonneville Power Administration	No	
Dominion	No	
Duke Energy	No	

Organization	Yes or No	Question 2 Comment
Hydro One Networks Inc.	No	
PacifiCorp	No	
South Carolina Electric and Gas	No	
ODEC	No	Certification is a process that says the entity has the capability to meet the requirments applicable to them, but this does not mean that the entity will meet the requirements. The two are different and need to be kept that way. One time certification is fine, the region could ask for re-certification if they find defeciencies with the entity in their performance.
US Bureau of Reclamation	No	The Commission was very clear that the modification it was requesting for TOP-006 could involve new capabilities for the Balancing Authority, the Transmission Operators and possibly the Reliability Coordinator.
Midwest ISO	No	The Midwest ISO believes a basic set of tools should be required for Reliability Coordinators. We believe they should part of the Reliability Standards so they will be part of the three-year audit cycle to ensure that the Reliability Coordinators maintain this basic tool set.
Western Electricity Coordinating Council	No	We agree that certification should be a one-time process and that the compliance audits of entities every 3 years should adequately address the issue of capabilities without recertification.
Xcel Energy	No	Given that there is no re-certification process, the proposed SAR should address the tools required by entities to address the real time monitoring issues.
Response: Thank you for your comment.		
American Electric Power	No	Given the limitations described, it seems appropriate to proceed with the standards development process to resolve these reliability issues as advocated by the SDT. AEP is hopeful that efforts will continue on the certification front to meet the reliability concerns expressed in this SAR as well. Ultimately, we believe that the NERC certification process of functional entities to ensure that the right tool set is in place and operating correctly is preferable to allowing, by administrative registration alone, to begin operating and then, afterwards, trying to invoke standards to address operating issues that could have been avoided up-front.
Response: In order to make the arguments for certification heard in the proper forum, industry representatives should forward the changes proposed to the NERC		

Organization	Yes or No	Question 2 Comment
Compliance and Certification Committee. The SAR DT appreciates the support indicated for proceeding with the standards effort at this time.		
FirstEnergy	No	While we agree the changes proposed in this SAR are not suited to the organization certification process, we are unclear as to why the Project 2007-03 SDT feels this project cannot be combined with theirs. Part of their responsibility appears to be managing the rules for the use of the System Operator tools. This SAR proposes to require a set of tool capability and performance. It would seem logical to expect the team responsible for specifying the use of system operator tools would have the skill set to determine the tool set make up and the performance needed from to those tools to produce an outcome consistent with the reliability of the BES. If left as separate projects, a high degree of coordination seems necessary to ensure the tools required and the use of those tools are sufficiently covered by the standards.
Response: The Project 2007-03 SDT thought it best to restrict the TOP family of standards to operating issues as opposed to mixing in capability requirements. Since the SAR for this project had been posted during the Project 2007-03 deliberations, the Project 2007-03 SDT saw an opportunity to achieve their goal of cleaning up the TOP family of standards to include only operating requirements. Both projects have the same NERC staff coordinator so coordination should not be a problem.		
MRO NERC Standards Review Subcommittee	No	Wouldn't this be covered by NERC BOT approved PER-005-1 as a reliability related task?
Response: No - Training operators on capabilities, as described in PER-005-1, does not address the items covered in this SAR such as performance metrics of those capabilities. No change made.		
Entergy Services	Yes	
SERC OC Standards Review Group	Yes	Some of the requirements (to have a certain capability or if we are forced there by FERC, a certain type of tool) best belong in certification. However, we agree that a requirement to have greater than a minimum certain 12 month-ending availability of an analytical capability and a requirement to have greater than a certain minimum quality of solution as measured on a 12 month-ending basis could better be addressed as a Reliability Standard. That is, the existence of a capability belongs in certification. Operational attributes of this capability belong in Reliability Standards. A demonstration of the functionality should be in the certification process, however once an entity is certified then compliance to performance metrics, availability parameters, etc could be in a standard. If an entity meets the performance metrics then obviously they must have the tools.
E.ON U.S.	Yes	A demonstration of the functionality should be in the certification process, however once an entity is certified then compliance to performance metrics, availability parameters, etc could be in a standard. If an entity

Organization	Yes or No	Question 2 Comment
		meets the performance metrics then obviously they must have the tools.
Response: Thank you for your support of moving forward with the standards process for performance metrics et al.		
Ameren	Yes	First of all, the team asserts in this question that FERC Order 693 requires the team to address "tool capability". Yet it disingenuously has renamed itself to talk about capabilites and NOT tools. It therefore begs the question, "Why would this SAR be better to address 693's "tools". Just because recertification is not currently in the process does not mean it could not be added, especially in cases where fundamental qualifications change.
Response: The SAR DT is dealing directly with Order 693 in stating capabilities as cited in paragraph 1660: "…note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System". Note that the use of minimum here does not imply a least common denominator approach as shown in paragraph 906: "We do not believe that the identification of minimum capabilities translates to "lowest common denominator". No change made. It is outside the scope of the SAR DT to suggest changes to the certification process. In order to make the arguments for certification heard in the proper forum, industry representatives should forward the changes proposed to the NERC Compliance and Certification Committee.		
Pepco Holdings, Inc.	Yes	Performance based reliability standards will ensure compliance. There is no need for measuring the physical performance of the tools used to meet those reliability performance requirements.
Response: The SAR DT does not believe that performance-based reliability standards, in and of themselves, ensure compliance. The SAR DT believes that the SAR directly addresses the competency element of the proposed results-based reliability standard effort. In the presentation to the NERC Board of Trustees (Proposal to Develop Results-Based Reliability Standards), the following example was quoted: "The analogy in airline safety would be a performance based requirement to avoid plane crashes. The cost of failure is too high to rely solely on enforcing compliance after such a failure. Like airline safety, bulk power system reliability requires additional, preventive requirements to reduce the risks of failure to acceptable tolerance levels." No change made.		
Manitoba Hydro	Yes	Though the introduction of a new standard is not welcome, this appears to be the only way to ensure measurable and enforceable goals.
Response: Thank you for your support.		
Georgia System Operations Corporation	Yes	Yes, the issues addressed in the proposed SAR belong in a certification process. Why, because there is no adequate certification process today, should a certification issue be turned into a Reliability Standard issue? Having certain capabilities is a certification issue and should be addressed by fixing the certification process. Certification processes should apply criteria to entities that have already been certified. Certification should

Organization	Yes or No	Question 2 Comment
		not be a one time process. There should be a certification and re-certification process. There was no operational history associated with mandatory reliability standards before June 2007. Such an operational history is being built now. After developing and putting in place an adequate certification program, then there will be an operational history associated with certification and re-certification. Certification criteria that deal with real-time operations or data should be evaluated by a certification team to determine if the entity has adequate functionality to be certified. Certification should not rely on the Compliance Monitoring and Enforcement Program (CMEP) to prove adequate functionality when there are violations of standards or on an on-going basis. There should be a separate certification (or capability verification) program to prove that. The issues raised by FERC should be addressed by first revamping all NERC requirements to risk-informed, performance-based requirements and developing a capability verification (certification) program. Then with a new slate of comprehensive, measurable, and auditable requirements and with a capability verification program, the original issues of FERC would be addressed. It is easy to perceive how having these things could eliminate the root problems and therefore the need to come up with solutions. That should satisfy and sustain a mandatory and enforceable status for those FERC directives. This SAR does not need to move forward to address the FERC directives.
Response: It is outside the scope of the SAR DT to suggest changes to the certification process. In order to make the arguments for certification heard in the proper forum, industry representatives should forward the changes proposed to the NERC Compliance and Certification Committee. The SAR DT does not believe that performance-based reliability standards, in and of themselves, ensure compliance. The SAR DT believes that the SAR directly addresses the risk-based element of the proposed results-based reliability standard effort. In the presentation to the NERC Board of Trustees (Proposal to Develop Results-Based Reliability Standards), the following example was quoted: "The analogy in airline safety would be a performance based requirement to avoid plane crashes. The cost of failure is too high to rely solely on enforcing compliance after such a failure. Like airline safety, bulk power system reliability requires additional, preventive requirements to reduce the risks of failure to acceptable tolerance levels." The SAR DT has no control over the certification process and is working under the existing rules and procedures to fill a reliability gap. No change made.		
Public Service Enterprise Group Companies	Yes	Yes, tools and tool capabilities are better handled within a certification process, that is, a certification that the entity has tools that are needed to meet the requirements of a standard. The certification process could be conducted initially and as a periodic re-certification if that is deemed necessary.
Response: It is outside the scope of the SAR DT to suggest changes to the certification process. In order to make the arguments for certification heard in the proper forum, industry representatives should forward the changes proposed to the NERC Compliance and Certification Committee. No change made.		

3. The approach taken by the Standards Development Program is not to write new requirements that assess basic capabilities used to achieve performance measured through other requirements within the Reliability Standards. The SAR DT has researched the standards and concluded that other requirements do not presently exist to adequately cover the issues raised in the SAR. Do you agree with this position? If not, please identify existing standard requirements that would apply and explain how these requirements accomplish the goals of the proposed SAR (including the Order 693 directives).

Summary Consideration: The majority of the commenters agreed with the SAR DT's position. However, based on industry comments, the SAR DT has added the BAL family of standards to the list of applicable standards to be reviewed.

The SAR DT agrees with commenters who pointed out that duplication or conflict of requirements is to be avoided. Including the TOP, IRO, BAL, and COM-001 standards to the list of standards that the eventual SDT must review should obviate any concerns on duplication or conflict of requirements.

Organization	Yes or No	Question 3 Comment
Ameren	No	
Response: Without specific comments as to your reason for the 'No' comment, the SDT can't respond.		
American Electric Power	No	AEP believes that elements identified in the detailed description portion of the SAR are largely covered in the existing standards, including those shown below (Table 1). The roll-up of SAR functions from SAR version 1 to a higher level descriptor in SAR version 2 does not seem to limit the relevance of all of the listed standards that AEP has researched. We are concerned that repetition of requirements across multiple standards may create ambiguity if alternative requirements or methods are defined from one to the other. The repetition also establishes the possibility of compounding violations for a single infraction. To the extent that new requirements are needed to address operational gaps, we believe that these should be made in the next revision of the applicable existing standards. TABLE I - Existing NERC Reliability Standards addressing Alarming, Telemetry, Network Analysis, Related Performance Metrics (Availability and Quality), and Processes and Procedures supporting Real-Time Tools (Change Mgt., Maintenance Coordination, and Failure Notification) : Alarming COM-001-1.1 does have some language related to the alarming of vital telecommunications facilities for voice and data.

Organization	Yes or No	Question 3 Comment
		TOP-006-2 stress the importance of monitoring equipment to be used to 'alarm' or bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action. IRO-002-2, gives direction on the alarming management and awareness systems that need to be in place for the RC. Telemetry BAL-001-0, dealing with the ACE equation along with Control Performance Standards (CPS1 and CPS2) BAL-004-0, addressing Time Error Corrections BAL-005-0.1b, focuses on the telemetry components necessary for calculating the ACE equation BAL-006-1.1, tasks the Balancing Authorities to calculate and record hourly Inadvertent Interchange IRO-004-1, details the information that needs to be sent to the RC for reliability studies to be performed IRO-005-3, breaks down most of the parameters that a RC would need to receive for monitoring the BES TOP-002-2, highlights that changes in transmission facility status, along with ratings should be monitored and conveyed to the RC and BA TOP-005-2 is the Operational Reliability Information standard that lays out all of the data that needs to be updated at least every ten minutes TOP-006-2 is another standard focused on monitoring system conditions. VAR-001-1 also is offering details on what data should be pipelined back to the operating control centers from the BES. Network Analysis IRO-004-1, discusses the ability for the RC, TO, and BA to conduct next-day reliability analyses to ensure that the BES can be operated reliably TOP-002-2, looks at the performance of current-day, next-day, and studies operational studies in conjunction with neighboring BA(s) and TO(s). TOP-002-2, also address the thermal and voltage contingency analysis that needs to be performed. IRO-002-2, details the analysis that needs to take place via state estimation and other visualization tools. Performance Metrics for Availability and Quality Availability

Organization	Yes or No	Question 3 Comment
		BAL-005-0.1b, R8 looks at SCADA availability to gather data and calculate ACE. This requirement also addresses the availability of Frequency Metering equipment (99.95%). COM-001-1.1, stresses the diversity and redundancy of communication paths for the available exchange of Interconnection and operating information, internally and externally to AEP. EOP-008-0, emphasizes the development of a plan to ensure the monitoring and control of transmission, distribution and generation assets even with the loss of the Control Center. Quality BAL-005-0.1b, R17 breaks down the accuracy of the metering devices for time error and frequency measurements BAL-006-1.1 requires adjacent balancing authorities to have common megawatt-hour meters at the interconnection point. IRO-005-3, discusses the importance of operating to the most limiting element if there is a discrepancy between various entities monitoring the same facilities. TOP-006-2 generically states that sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions. Processes and Procedures supporting Real-Time Tools: Change Mgt., Maintenance Coordination, and Failure Notification Change Management FAC-009-1, obligates the communication to RC(s), PA(s), TP(s), and TO(s) for new facility ratings on the Bulk Electric System. TOP-002-2, implies that there should be a facility change notification system in place for neighboring entities to use uniform line identifiers when referring to interconnected facilities. BAL-004-0, addressing Time Error Corrections Maintenance Coordination FAC-009-1, it is implied that these changes will be applied to the real time computer model with alterations to facility ratings on the Bulk Electric System. TOP-002-2, talks about each BA and TO maintaining accurate computer models for analyzing and planning system operations. Failure Notification IRO-005-3, highlights the responsibility to identify significant issues with ACE that can attribute to other errors, such as frequency error and Time error. As the SDT has described, the directives in Order 693 relate to IRO-002 and TOP-006 and indicate a desire

Organization	Yes or No	Question 3 Comment
		for a minimum set of capabilities. If the present SDTs for the referenced projects do not currently have these reliability issues in their scope, it would seem appropriate for NERC to slate these improvements for the next version of these respective standards.
Response: The SAR DT revised the SAR in the second posting to include the possibility of revising existing standards based on your research and comments. However, the SAR DT only included TOP, IRO, and COM standards. Upon further review, the SAR DT agrees that the BAL family of standards should be included in the list of applicable standards since they deal with reliability-based data. The other standards cited do not currently contain requirements addressing the capabilities envisioned in the SAR. The eventual SDT will have the ability to create new standards or revise existing standards. If they create new standards or revise existing standards, one of their responsibilities is to ensure that there will be no conflicting or redundant requirements in other standards. If one were to wait until the individual standards were to come up for revision, there would be a major coordination problem as some standards would be revised prior to others. In addition, there could be a lengthy period of time before these standards come up for revision again and the reliability gap from lack of requirements in this area will be open for that period of time. No change made.		
South Carolina Electric and Gas	No	BAL-005 R8, R14, and R16 define the BAs requirments for monitoring real-time data for the operation of AGC. The new standard should not confict with these requirements.
Response: The SAR DT agrees that the BAL family of standards should be included in the list of applicable standards since they deal with reliability-based data.		
SERC OC Standards Review Group	No	COM-002 R1 states "...voice and data links" shall be "...available for addressing a real-time emergency condition". The SDT should consider clarifying this point in relation to the performance metrics, availability parameters, etc as outlined in this SAR.
E.ON U.S.	Yes	COM-002 R1 states "...voice and data links" shall be "...available for addressing a real-time emergency condition". The SDT should consider clarifying this point in relation to the performance metrics, availability parameters, etc as outlined in this SAR.
Response: The SAR DT does not see the applicability of this standard to the concepts expressed in the SAR. COM-002 is describing physical assets and the SAR is dealing with performance issues. No change made.		
ISO New England Inc	No	See answer to #1 above. Also, in a Results/Performance Based standards world, this is a moot point. If you do not have the necessary tools, whatever your company has determined that those may be, you will violation Standard Requirements. You will, for example, violate an IROL, fail to recover from a Reportable Event, etc.
Hydro-Québec TransEnergie	No	See the response to question 1 above.

Organization	Yes or No	Question 3 Comment
(HQT)		In a Results/Performance Based standards world, this is not a valid point. Without the necessary tools, whatever those have been determined to be, Standard Requirements will be violated. An IROL will be violated, failure to recover from a Reportable Event will result in a DCS violation, etc.
Northeast Power Coordinating Council	No	See the response to Question 1 above. In a Results/Performance Based standard this is not a valid point. Without the necessary tools (whatever those have been determined to be), Standard Requirements will be violated. An IROL will be violated, failure to recover from a Reportable Event will result in a DCS violation, etc.
Response: See response to #1 above. The SAR DT does not see any point of conflict between the proposed results-based reliability standards effort and the proposed content of any eventual standard(s) or changes to existing standard(s) that this SAR might generate. Indeed, the SAR DT believes that the SAR directly addresses the competency element of the proposed results-based reliability standard effort. In the presentation to the NERC Board of Trustees (Proposal to Develop Results-Based Reliability Standards), the following example was quoted: “The analogy in airline safety would be a performance based requirement to avoid plane crashes. The cost of failure is too high to rely solely on enforcing compliance after such a failure. Like airline safety, bulk power system reliability requires additional, preventive requirements to reduce the risks of failure to acceptable tolerance levels.” No change made.		
IRC Standards Review Committee	No	See comment under Q1 and Q2, above.
Pepco Holdings, Inc.	No	See response to Q1 and Q2
Response: See responses to Q1 & Q2 above.		
Georgia System Operations Corporation	No	The best use of NERC’s and the industry’s thinly stretched resources is to work on the project to revise the entire set of standards to result in only the necessary risk-informed, performance-based requirements. Then there should be no gap of requirements. The approach taken by the Standards Development Program, to not write new requirements that assess basic capabilities used to achieve performance measured through other requirements within the Reliability Standards, would result in no need for this SAR because all necessary performance (of the bulk power system) requirements would then be in the Reliability Standards. Rather than adding more requirements, NERC should eliminate unnecessary requirements to a number of important performance-based requirements. Resources are being stretched thinner and thinner. Resources spend time complying with the letter of unnecessary, poorly worded requirements rather than complying with the spirit of what should be required and the translation of that spirit into literal performance-based requirements. Much time is also spent reviewing, commenting, and voting on all of the other existing NERC projects. If it came to a

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>choice of performing only the project to revise the standards to result in only the necessary risk-informed, performance-based requirements or performing all of the other projects in NERC’s 3 year plan, it would do more good for reliability and for compliance enforcement to accomplish only that one performance-based project. In fact, rather than doing all of the projects, it would be best for the sake of the limited amount of resources to put a hold on most (if not all) of the other projects and to work only on this one comprehensive project. The “staffing” and content of the ongoing and existing projects should be reorganized to be merged into and organized around the comprehensive results-based project and not around the existing very many separate projects that sprang up at different times with different objectives and perspectives. Performing this project first would likely correct the issues or problems which lead to the creation of many of the existing projects. Many of the other projects could be cancelled.</td></tr>
<tr><td colspan="3">Response: The Standards Committee sets the priority as to what projects are worked on. That is not within the scope of the SAR DT. If the Standards Committee decides that this SAR is not worthy of continuing, they will take the appropriate steps to curtail it.

The SAR DT believes that the SAR directly addresses the competency element of the proposed results-based reliability standard effort. No change made.</td></tr>
<tr><td>Western Electricity Coordinating Council</td><td>No</td><td>We believe the current requirements in the standards are adequate to address the basic capabilities required of the RCs. However, the requirements applicable to RCs are more specific in many cases than the requirements applicable to other entities.</td></tr>
<tr><td colspan="3">Response: Order 693 directs the ERO to make changes to the standards to address identified reliability gaps in the IRO and TOP standards. This undermines the basis for the statement made by WECC. The SAR DT believes that the existing requirements for the Reliability Coordinator do not address the aspects of performance, maintenance, and capability that are the subject of this SAR and as pointed out do not apply to other functional entities. No change made.</td></tr>
<tr><td>Duke Energy</td><td>Yes</td><td>However the Standards Drafting Team must be careful not to duplicate existing requirements in other standards, and until we see a draft it’s difficult to say there won’t be any duplication. For example, the Detailed Description of the SAR has a bullet “Evaluating the impact of ‘what if’ events on the current or future state of the BES.” This could duplicate TOP-002-2 Requirement R6 which states that “Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.</td></tr>
<tr><td colspan="3">Response: The SAR DT agrees that duplication must be avoided. The eventual SDT will have the ability to create new standards or revise existing standards. If they create new standards or revise existing standards, one of their responsibilities is to ensure that there will be no conflicting or redundant requirements in other standards as identified in the SAR including the TOP standards. No change made.</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	Yes	As much as we desire NOT to see a new standard, by examining the SAR and related FERC Order 693, the following goals: Based on the SARS Detailed Description, the following goals are: o describe capability characteristics o availability parameters o performance metrics o failure notification o maintenance coordination o change management o independent process monitor (watchdog) o monitoring power system data in real time o exchanging power system date in real time and from FERC 693 905 - RC has minimum set of tools 906 - Identify minimum capabilities and not tools (tools become obsolete) 1660 - Minimum set of analytical tools (not specific tools)would require modification of requirements from quite a few different Standards.
Response: The SAR DT does not see that the changes suggested add any clarity to the Detailed Description. No change made.		
AECI System Operations	Yes	
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Dominion	Yes	
Entergy Services	Yes	
Exelon	Yes	
FirstEnergy	Yes	
Hydro One Networks Inc.	Yes	
Independent Electricity System Operator	Yes	
Midwest ISO	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 3 Comment
US Bureau of Reclamation	Yes	
Xcel Energy	Yes	
NERC Standards Review Subcommittee	Yes	N/A
Response: Thank you for your support.		

4. Does the revised Detailed Description of the SAR provide sufficient details for the eventual Standard Drafting Team to execute the SAR? If not, please identify areas of insufficient detail and provide suggested wording for increased clarity.

Summary Consideration: The majority of commenters agree that sufficient details have been provided. Two small clarifying changes have been made to the SAR based on suggestions made in response to this question.

Detailed description: Develop or revise standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, failure notification, and maintenance (vetted by the industry through the Reliability Standards comment process)of functionality for:

- Monitoring power System data in Real-time.
- Exchanging power System data in Real-time.
- Alerting System Operators in Real-time to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an independent process monitor.
- Determining the current state of the BES.
- Evaluating the impact of 'what if' events on the current state of the BES.

Organization	Yes or No	Question 4 Comment
ISO New England Inc		See answer to #1 above.
Northeast Power Coordinating Council		See the response to Question 1 above.
Ameren	No	see general comment in 1
Hydro-Québec TransEnergie (HQT)	No	See the response to question 1 above.
Response: See response to #1 above.		
PacifiCorp	No	

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">Response: Without a specific comment, the SDT is unable to respond.</td></tr>
<tr><td>E.ON U.S.</td><td>No</td><td>Bullet 5 of the Detailed Description references “...future state of the BES”. The SDT needs to be cautious in defining what this means or remove that language altogether. The other bullets clearly spell out “Real-time” which defined by the NERC Glossary is “Present time as opposed to future time”. Bullet 5 appears to contradict the other bullets in its timeframe.</td></tr>
<tr><td>SERC OC Standards Review Group</td><td>No</td><td>Bullet 5 of the Detailed Description references: “...future state of the BES”. The SDT needs to be cautious in defining what this means or remove that language altogether. The other bullets clearly spell out “Real-time” which defined by the NERC Glossary is “Present time as opposed to future time”. Bullet 5 appears to contradict the other bullets in its timeframe scope. “The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”</td></tr>
<tr><td colspan="3">Response: The SAR DT agrees that ‘future’ is not needed for Real-time Monitoring and Analysis Capabilities and has deleted that term from the SAR language.
Detailed description: Develop or revise standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, failure notification, and maintenance (vetted by the industry through the Reliability Standards comment process)of functionality for:
• Monitoring power System data in Real-time.
• Exchanging power System data in Real-time.
• Alerting System Operators in Real-time to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an independent process monitor.
• Determining the current state of the BES.
• Evaluating the impact of ‘what if’ events on the current state of the BES.</td></tr>
<tr><td>Public Service Enterprise Group Companies</td><td>No</td><td>Monitoring is difficult to describe in a standard. The SAR has the potential to result in a standard that creates an undue administrative burden that is highly subjective, especially in the context of a compliance audit.
Also, the subject matter of the SAR appears to be applicable to tasks necessarily performed by transmission operators but not necessary for generator operators. GOP should be eliminated from the applicable entities.</td></tr>
<tr><td colspan="3">Response: The SAR DT understands your concern. However, this is just a SAR at this point and the rather generic language would seem to be appropriate here. There is almost certainly going to be some documentation requirements in the eventual standard(s) or revisions although the movement to results-based standards should minimize this. The eventual SDT will specify any Requirements and Measures needed and vet them with the industry through the comment and ballot</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
periods. No change made. The Generator Operator is included here because it owns reliability data that is essential to the Transmission Operators and Balancing Authorities and the quality of that data is of concern. The focus on capabilities is different for the various reliability entities and the eventual SDT will need to define that focus. For example, the Generator Operator would not be expected to perform network analysis. The SAR DT continues to believe that the eventual SDT needs to have the flexibility to include or not include the Generator Operator. No change made.		
FirstEnergy	No	See comments provided in item 1 above. Also, on Pg. 2 of the SAR it would be more helpful if it specifically stated the following regarding FERC directives: 1. "In Par. 905 of Order 693 '... the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe that this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. Further, as noted by Dominion, such a requirement promotes a more proactive approach to maintaining reliability'."2. "In Par. 1660 of Order 693, FERC directed modifications to TOP-006-1 1660 '... related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System. In response to APPA that the inclusion of specific analytical tools is counterproductive because the tools will become obsolete, we note that we are not seeking specific analytical tools, but rather minimum capabilities'." Also, it should be noted that the SDTs currently working on IRO-002 and TOP-006, Project 2006-06 and 2007-03, respectively, are proposing to retire both of these standards. Therefore, the eventual SDT for this Project 2009-02 will have to determine the appropriate standards to include new requirements for Real-time monitoring and analysis capabilities.
Response: See response to #1 above. The present wording of the SAR contains a reference to the appropriate paragraphs of Order 693 and the SAR DT feels that this is sufficient. No change made. The SAR DT agrees that the eventual SDT should have the capability to create or revise standards as deemed appropriate and be required to respond to all FERC directives on these issues. The language of the SAR assures that these obligations will be passed on to the eventual SDT. No change made.		
US Bureau of Reclamation	No	The SAR needs to incorporate the language from Order 693. The scope should be limited to the modification of respective standards.
Response: The present wording of the SAR contains a reference to the appropriate paragraphs of Order 693 and the SAR DT feels that this is sufficient. No change made. TOP-006 and IRO-002 are not the only standards that address the topics in the SAR. As pointed out by other industry commenters, BAL and COM-001 need to be		

Organization	Yes or No	Question 4 Comment
reviewed as well. In addition, the eventual SDT needs the flexibility to create new standards if they determine that all of the topics in the SAR can not be addressed by modifications to existing standards. No change made.		
South Carolina Electric and Gas	No	There are some terms used in the SAR that need to be clarified, such as "watch dog". Better define what is meant by "independent process monitor". Is the group specifying how the system should function or specific tool that should be used.
Response: The term 'watch dog' is only cited as a possible example and the SAR DT agrees that it is not needed in a SAR and has deleted the terminology. **Detailed description**: Develop or revise standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, failure notification, and maintenance (vetted by the industry through the Reliability Standards comment process)of functionality for: • Monitoring power System data in Real-time. • Exchanging power System data in Real-time. • Alerting System Operators in Real-time to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an independent process monitor. • Determining the current state of the BES. • Evaluating the impact of 'what if' events on the current state of the BES. 'Independent process monitor' is a well understood term and implies a process that is separate from what is being monitored. No change made.		
Western Electricity Coordinating Council	No	We are not certain we understand the meaning of the reference to a watch dog. This functionality shall include an independent process monitor (e.g., watchdog). The IRO standards cover the items listed in the detailed description, so the STD should not be duplicative of the IRO standards.
Response: The term 'watch dog' is only cited as a possible example and the SAR DT agrees that it is not needed in a SAR and has deleted the terminology. **Detailed description**: Develop or revise standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, failure notification, and maintenance (vetted by the industry through the Reliability Standards comment process)of functionality for: • Monitoring power System data in Real-time. • Exchanging power System data in Real-time. • Alerting System Operators in Real-time to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an		

Organization	Yes or No	Question 4 Comment
independent process monitor. • Determining the current state of the BES. • Evaluating the impact of 'what if' events on the current state of the BES. The SAR DT agrees that duplication must be avoided. The eventual SDT will have the ability to create new standards or revise existing standards. If they create new standards or revise existing standards, one of their responsibilities is to ensure that there will be no conflicting or redundant requirements in other standards as identified in the SAR including the IRO standards. No change made.		
Manitoba Hydro	Yes	Very tangible details such as telemetry, alarming, Network Analysis terms were removed from the SAR and replaced with vague terms such as: o describe capability characteristics o availability parameters o performance metrics o failure notification o maintenance coordination o change management o independent process monitor (watchdog) o monitoring power system data in real time o exchanging power system date in real time. If it wasn't for the SAR redline copy (that contained telemetry, alarming, Network Analysis) the above terminology would be difficult to assess. 1. Capability characteristics of what, analytical tools, alarms, telemetry, all these items? 2. Availability parameters of what, analytical tools, alarms, telemetry, all these items? 3. Failure notification of what, analytical tools, alarms, telemetry, all these items? 4. Maintenance coordination of what, analytical tools, alarms, telemetry, all these items? 5. Change Management (See note 4 in question 1) of what, analytical tools, alarms, telemetry, all these items? 6. Under which of the above SAR details could you assume FERC order 693 "minimum set of analytical tools" falls under? 7. What does "Independent process monitor (watchdog)" mean is that an analytical tool or is that an RC? 8. Exchanging and monitoring power system date in real time, isn't that covered in TOP-005 1.1, "Attachment 1 - TOP-005-1.1"?
Response: 1. through 4. The SAR DT was responding to a majority of industry comments and the FERC directives in changing the specific terminology in the first posting of the SAR. The capability characteristics, etc. refer to the subsequent bullets in the Detailed Description section of the SAR. No change made. 5. The term 'change management' has been deleted based on earlier comments. 6. In Order 693 where it seems to call for a minimum set of analytical tools, this is clarified later as capabilities in paragraph 1660. No change made.		

Organization	Yes or No	Question 4 Comment
7. The term 'watch dog' is only cited as a possible example and the SAR DT agrees that it is not needed in a SAR and has deleted the terminology. **Detailed description**: Develop or revise standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, failure notification, and maintenance (vetted by the industry through the Reliability Standards comment process)of functionality for: • Monitoring power System data in Real-time. • Exchanging power System data in Real-time. • Alerting System Operators in Real-time to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an independent process monitor. • Determining the current state of the BES. • Evaluating the impact of 'what if' events on the current state of the BES. 'Independent process monitor' is a well understood term and implies a process that is separate from what is being monitored. No change made 8. The SAR DT agrees that duplication must be avoided. The eventual SDT will have the ability to create new standards or revise existing standards. If they create new standards or revise existing standards, one of their responsibilities is to ensure that there will be no conflicting or redundant requirements in other standards as identified in the SAR including the TOP standards. No change made.		
AECI System Operations	Yes	
American Electric Power	Yes	
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Dominion	Yes	
Duke Energy	Yes	
Entergy Services	Yes	
Exelon	Yes	
Hydro One Networks Inc.	Yes	

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	Yes	
Midwest ISO	Yes	
Xcel Energy	Yes	
NERC Standards Review Subcommittee	Yes	N/A
Response: Thank you for your comment.		

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard: Project 2009-02: Real-time Reliability Monitoring and Analysis Capabilities
Original Request Date: June 4, 2009
Revised Date: January 15, 2010
Revised Date: March 31, 2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name:	Jack Kerr	X	New Standard(s)
Primary Contact:	Dominion Virginia Power	X	Revision to existing Standard
Telephone: Fax:	1.804.273.3393 1.804.273.2405	☐	Withdrawal of existing Standard
E-mail:	jack.kerr@dom.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

The new or revised standard(s) will establish requirements for the functionality, performance, and maintenance of Real-time Monitoring and Analysis capabilities for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* dated April 2004, a principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools. In addition, the failure of control computers and alarm systems, incomplete tool sets, and the failure to supply network analysis tools with correct System data on August 14 contributed directly to this lack of situational awareness. Also, the need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations.

Recommendation 22 of the Blackout Report states "Evaluate and adopt better real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate real-time tools and their usage within the industry. The Task Force produced a report "*Real-Time Tools Survey*

Analysis and Recommendations", dated March 13, 2008 that included recommendations for the functionality, performance, and management of Real-time tools.

There are 2 directives in FERC Order 693 relating to minimum tool capabilities that need to be addressed. One directive pertains to IRO-002 and is described in paragraphs 905 & 906 of Order 693. The second directive pertains to TOP-006 and is described in paragraph 1660. These directives clearly indicate the desire for a minimum set of capabilities as opposed to specific tools. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC.

This SAR addresses selected recommendations in the RTBPTF Report as determined by the Real-time Best Practices Standards Study Group: Project 2009-02 and addresses the directives in Order 693 referenced above.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The scope of the SAR is to establish requirements for the monitoring and analysis capabilities provided to System Operators and used to support Real-time System Operations. The SAR addresses availability parameters, performance metrics, and procedures for failure notification, maintenance coordination, and change management. The intent is to describe 'what' needs to be done but not 'how' to do it.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Develop or revise standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, failure notification, and maintenance (vetted by the industry through the Reliability Standards comment process)of functionality for:

- Monitoring power System data in Real-time.
- Exchanging power System data in Real-time.
- Alerting System Operators in Real-time to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an independent process monitor.
- Determining the current state of the BES.
- Evaluating the impact of 'what if' events on the current state of the BES.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	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.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	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.
X	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.
X	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 service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	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.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	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.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power 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 of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability 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
TOP-xxx	The TOP family of standards is undergoing revision. The eventual SDT should have the flexibility to revise these standards or write new standards as best fits the task.
IRO-xxx	The IRO family of standards is undergoing revision. The eventual SDT should have the flexibility to revise these standards or write new standards as best fits the task.
COM-001-1.1	The eventual SDT should have the flexibility to revise this standard or write new standards as best fits the task.
BAL-xxx	The BAL family of standards should be included in the scope of this SAR because they do address reliability-based data. Therefore, the eventual SDT should have the flexibility to revise these standards or write new standards as best fits the task.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standard Authorization Request Form

Title of Proposed Standard: ~~-~~Project 2009-02: Real-time Reliability Monitoring and Analysis Capabilities	
Original Request Date: June 4, 2009	
Revised Date: January 15, 2010	
Revised Date: March 31, 2010	

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name:	Jack Kerr	X	New Standard(s)
Primary Contact:	Dominion Virginia Power	X	Revision to existing Standard
Telephone: Fax:	1.804.273.3393 1.804.273.2405	☐	Withdrawal of existing Standard
E-mail:	jack.kerr@dom.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)
The new or revised standard(s) will establish requirements for the functionality, performance, and ~~change management~~maintenance of Real-time Monitoring and Analysis capabilities for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* dated April 2004, a principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools. In addition, the failure of control computers and alarm systems, incomplete tool sets, and the failure to supply network analysis tools with correct System data on August 14 contributed directly to this lack of situational awareness. Also, the need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations.

Recommendation 22 of the Blackout Report states "Evaluate and adopt better real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate real-time tools and their usage within the industry. The Task Force produced a report "*Real-Time Tools Survey Analysis and Recommendations*", dated March 13, 2008 that included recommendations for the functionality, performance, and management of Real-time tools.

There are 2 directives in FERC Order 693 relating to minimum tool capabilities that need to be addressed. One directive pertains to IRO-002 and is described in paragraphs 905 & 906 of Order 693. The second directive pertains to TOP-006 and is described in paragraph 1660. These directives clearly indicate the desire for a minimum set of capabilities as opposed to specific tools. The existing projects that would have handled these issues (Project 2006-02 for IRO-002 and Project 2007-03 for TOP-006) have clearly indicated that they expect this SAR (Project 2009-02) to address the issues raised by FERC.

This SAR addresses selected recommendations in the RTBPTF Report as determined by the Real-time Best Practices Standards Study Group: Project 2009-02 and addresses the directives in Order 693 referenced above.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The scope of the SAR is to establish requirements for the monitoring and analysis capabilities provided to System Operators and used to support Real-time System Operations. The SAR addresses availability parameters, performance metrics, and procedures for failure notification, maintenance coordination, and change management. The intent is to describe 'what' needs to be done but not 'how' to do it.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Develop or revise standard(s) to describe the capability characteristics, such as availability parameters, performance metrics, ~~and procedures for~~ failure notification, and maintenance

~~coordination, and change management~~ (vetted by the industry through the Reliability Standards comment process)of functionality for:

- ~~•~~ Monitoring power System data in Real-time.
- Exchanging power System data in Real-time.
- ~~Emitting Real-time visible and audible signals to a~~Alerting System Operators in Real-time to events and conditions affecting the state of the Bulk Electric System (BES). This functionality shall include an independent process monitor ~~(e.g., watchdog)~~.
- Determining the current state of the BES.
- Evaluating the impact of 'what if' events on the current ~~or future~~ state of the BES.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	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.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	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.
X	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.
X	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 service (and reliability-related services) to serve the End-use Customer.

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Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	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.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	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.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power 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 of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability 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

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Related Standards

Standard No.	Explanation
TOP-xxx	The TOP family of standards is undergoing revision. The eventual SDT should have the flexibility to revise these standards or write new standards as best fits the task.
IRO-xxx	The IRO family of standards is undergoing revision. The eventual SDT should have the flexibility to revise these standards or write new standards as best fits the task.
COM-001-1.1	The eventual SDT should have the flexibility to revise this standard or write new standards as best fits the task.
BAL-xxx	The BAL family of standards should be included in the scope of this SAR because they do address reliability-based data. Therefore, the eventual SDT should have the flexibility to revise these standards or write new standards as best fits the task.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Concept White Paper

Concepts for Proposed Content of Eventual Standard(s) for Project 2009-02: Real-Time Monitoring and Analysis Capabilities

Real-time Monitoring and Analysis Capabilities
Standard Drafting Team
February 15, 2011

1.0 INTRODUCTION

FERC Order 693 indicates the need for a minimum set of capabilities to be available for System Operators to assist in making Real-time decisions. The work done by the Real-time Tools Best Practices Task Force (RTBPTF), which was formed by NERC in response to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* is the basis for the Real-time Monitoring and Analysis Capabilities SAR that was approved by the Standards Committee in April 2010 and the subsequent appointment by NERC of a Standard Drafting Team (RMACSDT) to develop a standard to satisfy the proposed issues described in the SAR utilizing the results-based standards methodology.

This White Paper is a description of the present thinking of the RMACSDT regarding standard requirements for Real-time monitoring and analysis capabilities. The paper consists of four sections that describe the major areas proposed to be addressed by the eventual standard(s). These areas are:

- Section 2 - Monitoring
- Section 3 - Data exchange
- Section 4 - Alarming
- Section 5 – Analysis

The SDT will also be crafting an Implementation Plan for any eventual standard(s) that will be vetted by the industry through comments and that will allow for sufficient time for applicable entities to bring their systems into compliance with any new requirements.

2.0 MONITORING

Monitoring is the first component in the process of establishing situational awareness for the System Operators so that they can rapidly assess the state of the Bulk Electric System (BES). In the context of this standard, "monitoring" implies System Operators viewing data in a manner that allows them to determine the state of the BES in Real-time and to take corrective and preventive actions when necessary. The types of data to be considered by the standard are:

- Real-time analog and status
  - Scanned
  - Calculated

For purposes of monitoring as described in this paper, this is data scanned by a central system from Data Collection Units (DCU) such as Remote Terminal Units (RTUs).

Calculated values are treated the same as scanned values in this paper.

It is proposed that requirements for monitoring will be applicable to Reliability Coordinators, Transmission Operators, and Balancing Authorities.

The following requirements are proposed for monitoring of Real-time data. These requirements assume that the Responsible Entity is utilizing an Energy Management System (EMS) and/or Supervisory Control and Data Acquisition (SCADA) system to collect the Real-time data.

2.1 PERFORMANCE

A performance parameter is proposed for each category of data collected and the data displayed to the operator.

2.1.1 Status Data

Status data shall be collected at a scan rate not to exceed 4 seconds.

2.1.2 Analog Data

In many systems analog data is collected at multiple scan rates depending on the applications in which the data is being used. It is proposed that all analog data, except the data identified in the BAL standards, is scanned at a rate not to exceed 10 seconds - the rate suggested in the RTBPTF report.

2.1.3 Data Display

All active displays utilized for visualization of the data discussed above shall update by the end of the next status or analog scan cycle, as stated above, following the scan in which the data was received by the central system. For example, status data should be updated within 4 seconds following the receipt of the scan by the central system.

2.2 AVAILABILITY

The SDT proposes two requirements for availability:

- A demonstrable procedure shall be developed describing the alternate plans and/or mitigating measures entities have in place when the data used to monitor BES or perform analyses on BES (see Section 5) becomes unavailable

- For each DCU, availability shall be calculated by dividing the number of “good” scans received at the central system by the number of scans scheduled to be received in a calendar month. (A ‘good’ scan is a complete packet of requested data returned to the central system.) The ratio of scans received to scans scheduled shall exceed 99% for a calendar month. This calculation can include alternate or backup data sources that provide data when the primary DCU is unavailable.

2.3 FAILURE NOTIFICATION

‘Failure’ is assumed to occur when a scan is not completed for any reason and it shall be notified after the 9th consecutive ‘failure’ occurs. The System Operator shall be notified of such failure within 60 seconds of the 9th consecutive ‘failure’.

2.4 MAINTENANCE

Each Responsible Entity shall provide the System Operator with approval authority for planned maintenance that impact monitoring capabilities.

3.0 DATA EXCHANGE

Data exchange, as discussed in this paper, refers to electronic exchange of data between two computer based control systems (EMS and/or SCADA) whether they are internal or external to each other. It is assumed that the data links discussed will utilize ICCP or an equivalent protocol. Data exchange, in this context, does not include RTUs or other similar types of DCUs. Required data sets to be exchanged are covered in proposed IRO-010-2 and TOP-003-2.

ICCP is the Inter-Control Center Communications Protocol (ICCP or IEC 60870-6/TASE.2 or latest release). It is an international standard used by utility organizations to provide data exchange over wide area networks (WANs) between utility control centers, utilities, power pools, regional control centers, and Non-Utility Generators.

Collecting and exchanging real-time data on power system status is one of the elementary steps in the complex process of developing the information that System Operators need to maintain situational awareness. Real-time reliability tools such as the state estimator and contingency analysis can only provide results that accurately represent current and potential reliability problems if these tools have Real-time analog and status data. The accuracy of the information that Real-time reliability tools provide depends on the accuracy of the data supplied to the tools. The quality of the results that Real-time reliability tools produce is also influenced by the breadth and depth of the portion of the BES for which Real-time data are collected, relative to the breadth and depth of the relevant Reliability Entity’s area of responsibility.

It is proposed that requirements for data exchange will be applicable to the Reliability Coordinator, Transmission Operator, Balancing Authority, and Generation Operator.

The following requirements are proposed for data exchange of Real-time data. These requirements assume that the Responsible Entity is utilizing an EMS and/or SCADA system utilizing ICCP or an equivalent protocol to exchange data.

3.1 PERFORMANCE

The SDT proposes the following requirements for data exchange performance:

- ICCP (or equivalent) data exchange must be redundant and the redundancy must be supplied through diverse routing.

- Entities shall develop data exchange agreements and comply with data specifications.

- Data exchange agreements must include the following:
    - Interoperability of ICCP and equivalent systems
    - Data access restrictions
    - Data naming conventions
    - Data management and coordination including data quality
    - Joint testing and data checkout
    - Monitoring of availability
    - Responsibility for failures
    - Restoration process

3.2 AVAILABILITY

The SDT proposes the following requirements for data exchange availability:

- Establish procedure for actions to be taken if some or all of the data exchanged is not available for a 30 minute timeframe.

3.3 FAILURE NOTIFICATION

Notification of link failure must be made to the System Operator within 60 seconds of when link failure occurred. Failure is identified as the inability to receive a complete data set regardless of reason.

3.4 MAINTENANCE

Each functional entity shall provide System Operators with approval authority for planned maintenance of its data exchange capabilities. Coordination with affected entities is required.

4.0 ALARMING

Alarms must be generated to alert System Operators in Real-time to events and conditions affecting the state of the BES. Alarms can be audible and/or visual. Alarms must be generated for the following reasons:

- Limit violations (for any defined limits including multiple limits on a single point)
- Uncommanded status changes
- DCU unavailability
- Data exchange link unavailability

Alarms are important to the safe and secure operation of the BES. System Operators depend on alarms to identify problems occurring or about to occur. All values measured or calculated by the EMS and/or SCADA must be subject to processing to determine either change of state or limit violations. If either of these conditions occurs, an alarm must be generated.

It is proposed that requirements for alarming will be applicable to Reliability Coordinators, Transmission Operators, and Balancing Authorities.

The following requirements are proposed for alarming of measured and calculated data.

4.1 PERFORMANCE

Performance issues such as volume and throughput of alarms are recognized as potential concerns but are generally handled in initial EMS/SCADA vendor specifications. It would be difficult if not impossible to measure in a production system. Therefore, no performance requirement is anticipated as part of this project.

4.2 AVAILABILITY

The SDT proposes the following requirements for alarming availability:

- No specific numeric value will be proposed for alarming availability.

- Establish a procedure for actions to be taken when the alarming functionality is unavailable for 10 consecutive minutes (see RTBPTF report, page 117, paragraph 4). For example, the Reliability Coordinator 'backs up' the Transmission Operator/Balancing Authority and vice versa and entities inform each other of failure of their alarming capability.

4.3 FAILURE NOTIFICATION

Notification of failure of the alarm processing function must be made to the System Operator within 60 seconds of when failure is detected. Notification of failure of alarming capability must be accomplished through independent failure notification where the system creating and presenting the notification is independent of the alarming functionality.

4.4 MAINTENANCE

Each functional entity shall provide System Operators with approval authority for planned maintenance of its alarming capabilities.

5.0 ANALYSIS

The intent of analysis in the context of this white paper is to focus on determining the current condition or state of the BES and evaluate the impact of ‘what if’ events on the state of the BES. The meanings of “current” and “what-if” are:

- Current - The current system condition or state is a function of the most recent system bus voltages, system topology, frequency, and line flows.

- ‘What if’ - Analyze the impact on the security of the current power system state of specific Contingencies or simulated outages of the BES such as lines, generators, or other equipment. This analysis should also include other system condition changes that would affect the BES such as Load. The analysis identifies problems such as line overloads or voltage violations that will occur if the system event or Contingency takes place.

The capability to determine the current state of the BES is critical for the System Operator to determine violations of reliability criteria in their area. By accurately determining the current state of the BES, the System Operator is thus capable of evaluating various ‘what if’ scenarios. Having the results of the ‘what if’ events before they happen allows System Operators to take the appropriate actions to prevent violations or have plans ready if such Contingencies were to occur.

It is proposed that requirements for analysis will be applicable to the Reliability Coordinator and Transmission Operator.

The following requirements are proposed for analysis of the current and “what-if” states of the BES.

5.1 PERFORMANCE

The requirements for Performance will address periodicity and quality.

5.1.1 Periodicity

The current and "what-if" analyses shall run based on the following conditions:

- Current analysis - Automated program required that runs periodically at no more than a 5 minute interval to determine the system's current condition or state. The analysis may be either a program that runs on the Reliability Coordinator's or Transmission Operator's EMS or through contracted services (3rd party, Reliability Coordinator, or other Transmission Operator).

- "What if" analysis - Automated program required that runs periodically at no more than a 10 minute interval (from pg. 117 of Blackout Report - #4.b) to analyze the impact on the security of the current power system state for specific Contingencies or simulated outages of the BES such as lines, generators, or other equipment. The analysis may be either a program that runs on the Reliability Coordinator's or Transmission Operator's EMS or through contracted services (3rd party, Reliability Coordinator, or other Transmission Operator).

5.1.2 Results Quality

Quality needs to be measured to ensure that the base case used by the automated analysis program(s) accurately represent the state of the system.

- For both current & "what if" analyses:
    - For Reliability Coordinator & Transmission Operator:
        - Compare physical 'tie' line values and generator injections plus selected interconnected transmission line flows from the automated analysis program(s) to actual metered values every time the program runs. These values have been selected because of the accuracy of the metering at those locations and their impact on the BES.
        - Compute the percentage deviation of the program values versus actual metered values
        - Compute the average of the percentages on a periodic basis and compare to the tolerance value. (Actual periodicity will be selected based on industry feedback.)
        - Tolerance must be +/- x%. (Actual value will be selected based on industry feedback.)

5.2 AVAILIBILITY

Responsible entities must establish a procedure for what to do if the program(s) is not available for more than 30 consecutive minutes.

Current - The automated programs must provide a solution every five minutes 99% of the time on a monthly basis.

'What if' - The automated programs must provide a solution every ten minutes 99% of the time on a monthly basis.

5.3 FAILURE NOTIFICATION

Notification of failure of the analysis capability to provide a solution to the System Operator must be made to the System Operator within 60 seconds of when failure is detected.

5.4 MAINTENANCE

Each functional entity shall provide System Operators with approval rights for planned maintenance of its analysis capabilities.

Informal Comment Form for Concept White Paper for Project 2009-02: Real-time Monitoring and Analysis Capabilities

Please **DO NOT** use this form to submit comments on the White Paper for Project 2009-02: Real-time Monitoring and Analysis Capabilities. This comment form must be completed by **April 4, 2011.**

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information
Concept White Paper for Project 2009-02: Real-time Monitoring and Analysis Capabilities

The SDT has created this white paper to illustrate the concepts it intends to pursue as the project unfolds. The goal of the white paper is to solicit industry feedback on the concepts to serve as input to the eventual creation of standards and requirements on the topic of Real-time monitoring and analysis capabilities. The SDT is striving to emphasize capabilities and is not proposing to require the use of any specific tools.

The SDT is actively pursuing industry feedback and strongly encourages industry to provide alternatives to the concepts presented using specific language where possible.

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 has proposed Section 2 for the concepts on monitoring. Do you support these concepts? If you do not support these concepts, please specify why you disagree and include specific alternative language to resolve your concern.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has proposed Section 3 for the concepts on data exchange. If you do not support these concepts, please specify why you disagree and include specific alternative language to resolve your concern.

   ☐ Yes, I agree with the concepts

   ☐ No, I do not agree with the concepts

   Comments:

3. The SDT has proposed Section 4 for the concepts on alarming. If you do not support these concepts, please specify why you disagree and include specific alternative language to resolve your concern.

   ☐ Yes, I agree with the concepts

   ☐ No, I do not agree with the concepts

   Comments:

4. The SDT has proposed Section 4 for the concepts on Analysis. If you do not support these concepts, please specify why you disagree and include specific alternative language to resolve your concern.

   ☐ Yes, I agree with the concepts

   ☐ No, I do not agree with the concepts

   Comments:

5. Are there any other capabilities that you feel are necessary to cover the general topic of Real-time monitoring and analysis capabilities. Please be as specific as possible in raising your ideas.

   Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2009-02 Real-time Monitoring and Analysis Capabilities
Informal Comment Period Open
February 16 – April 4, 2011

Now available at: http://www.nerc.com/filez/standards/Project2009-02_Real-Time_Monitoring_Analysis_Capabilities.html

Informal Comment Period Open through 8 p.m. on Monday, April 4, 2011

The Project 2009-02 Real-time Monitoring and Analysis Capabilities Standard Drafting Team has posted for a 45-day informal comment period a White Paper on proposed concepts to support the development of real-time monitoring and analysis standards. The White Paper, along with an unofficial Word version of the comment form, have been posted on the project Web page at http://www.nerc.com/filez/standards/Project2009-02_Real-Time_Monitoring_Analysis_Capabilities.html.

Instructions

Please submit comments using the electronic form.

Next Steps

The drafting team will consider the input received on the concept White Paper as it begins preparing to draft standards.

Project Background

The need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations. According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, dated April 2004, a principal cause of the August 2003 blackout was a lack of situational awareness, a result of inadequate reliability tools.

NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate real-time tools and their usage within the industry. The Task Force produced a report "Real-Time Tools Survey Analysis and Recommendations," dated March 13, 2008 that included recommendations for the functionality, performance, and management of real-time tools.

This project addresses recommendations from the August 2003 Blackout Report, the RTBPTF report, and two directives from FERC Order 693.

Standards 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 Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
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Unofficial Nomination Form

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Solicitation for Drafting Team Nominations

DO NOT use this form for submitting nominations. The electronic nomination form should be used to submit nominations and it is due prior to **8 p.m. Eastern, Friday, March 6, 2015.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form. If you have any questions, contact Mark Olson (via email) or by telephone at (404) 446-9760.

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.

The time commitment for these projects 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 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 team should be conducting outreach during development prior to posting to ensure all issues can be discussed and resolved.

Background

Project 2009-02 is included in the 2015-2017 Reliability Standards Development Plan (RSDP) approved by the NERC Board of Trustees (Board) on November 13, 2014. Formal development of this project was paused in 2011 and will resume to address outstanding Federal Energy Regulatory Commission (FERC) directives and issues that were not consolidated into Project 2014-03 TOP/IRO Revisions.

Project 2009-02 was initiated in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). From 2009 to 2011, a SAR drafting team developed a SAR and technical white paper to establish requirements for the "functionality, performance, and maintenance of

Real-time Monitoring and Analysis Capabilities."[1] In early 2011, formal development stopped to prioritize efforts on other projects.

In May 2013, NERC filed revised TOP and IRO Reliability Standards with FERC for approval (Projects 2007-03 and Project 2006-06). FERC expressed concerns with the proposed standards and retirements, including proposed retirement of currently-enforceable requirements for monitoring and analysis capabilities prior to completing the development of replacement requirements that address the outstanding FERC directives[2]. New TOP and IRO standards developed in Project 2014-03 address FERC concerns with the exception of some Real-time monitoring and analysis issues.

Some members of the original SDT have indicated that they are no longer available to continue participating in Project 2009-02. Nominations of subject matter experts (SMEs) are being sought to replace SDT members that are no longer participating, and to provide diverse technical experience, industry leadership, and regional and entity representation.

The SDT will consider the FERC directives and guidance, stakeholder input, and relevant industry reports for the purpose of revising a SAR for Standards Committee action and revising the white paper that was in development in 2011. The project page contains prior work.

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1 SAR is available at the following: http://www.nerc.com/pa/Stand/Project%20200902%20Realtime%20Reliability%20Monitoring%20and/2009-32_RTTSDT_Third_Posting_SAR_Clean_2010April1.pdf

2 FERC's November 21, 2013 TOP/IRO Notice of Proposed Rulemaking, P 57-61, 145 FERC ¶ 61,158

Please provide the following information for the nominee:	
Name:	
Title:	
Organization:	
Address:	
Telephone:	
Email:	

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 2009-02:

☐ ERCOT	☐ NPCC	☐ SPP
☐ FRCC	☐ RF	☐ WECC
☐ MRO	☐ SERC	☐ 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[3] 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	

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:	

[3] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

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

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Solicitation for Drafting Team Nominations

Now Available

Nominations are being sought for Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities drafting team (SDT) members through **8 p.m. Eastern, Friday, March 6, 2015**.

Original members of the Project 2009-02 SDT who desire to continue to participate are also requested to submit a nomination.

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. Detailed information is included on the unofficial Word version of the nomination form which can be found on the project page. Use the electronic form to submit nomination(s).

Project 2009-02 – Real-time Reliability Monitoring and Analysis Capabilities

Project 2009-02 is included in the 2015-2017 Reliability Standards Development Plan (RSDP) approved by the NERC Board of Trustees (Board) on November 13, 2014. Formal development of this project was paused in 2011 and will resume to address outstanding Federal Energy Regulatory Commission (FERC) directives and issues that were not consolidated into Project 2014-03 TOP/IRO Revisions.

Project 2009-02 was initiated in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). From 2009 to 2011, a Standard Authorization Request (SAR) SDT developed a SAR and technical white paper to establish requirements for the "functionality, performance, and maintenance of Real-time Monitoring and Analysis Capabilities."[1] Some members of the original SDT have indicated that they are no longer available to continue participating in Project 2009-02. Nominations of subject matter experts (SMEs) are being sought to replace SDT members that are no longer participating, and to provide diverse technical experience, industry leadership, and regional and entity representation.

[1] SAR is available at the following: http://www.nerc.com/pa/Stand/Project%20200902%20Realtime%20Reliability%20Monitoring%20and/2009-32_RTTSDT_Third_Posting_SAR_Clean_2010April1.pdf

The SDT will consider the FERC directives and guidance, stakeholder input, and relevant industry reports for the purpose of revising the SAR for Standards Committee action and revising the white paper that was in development in 2011.

Next Steps

The Standards Committee is expected to begin appointing members to the SDT in April 2015. Nominees will be notified shortly after they have been appointed to the drafting team**.**

For information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Mark Olson (via email) or by telephone at (404) 446.9760.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	Project 2009-02: Real-time Reliability Monitoring and Analysis Capabilities		
Date Submitted:	June 18, 2015		
SAR Requester Information			
Name:	Saad Malik		
Organization:	Peak Reliability		
Telephone:	970.776.5635	E-mail:	smalik@peakrc.com
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☐ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
To establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations.
Industry Need (What is the industry problem this request is trying to solve?):
According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* dated April 2004 (2003 Blackout Report), a principal cause of the August 14 blackout was a lack of situational awareness. Recommendation 22 of the 2003 Blackout Report states that the industry should "evaluate and adopt better Real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate Real-time tools and their usage within the industry. The Task Force produced the report *Real-Time Tools Survey Analysis and Recommendations* dated March 13, 2008 (RTBPTF Report)

SAR Information
that included recommendations for the functionality, performance, and management of Real-time tools. The FERC and NERC Staff Report *Arizona-Southern California Outages on September 8, 2011* (2011 Southwest Outage Report) also cited weaknesses in Real-time situational awareness and recommended improvements in Real-time monitoring and analysis capabilities. In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to System operators: • P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.* • P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.* • P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.* This SAR addresses the event reports, Order No. 693 directives, and recommendations from the RTBPTF Report that have not been addressed in other standards projects. The SAR Drafting Team also conducted a Technical Conference on June 4, 2015 to obtain stakeholder input on reliability objectives to be addressed in the proposed project.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Standards Drafting Team (SDT) shall develop requirements and definition(s), as needed, for Real-time monitoring and analysis capabilities to ensure effective operator situational awareness. The project will address recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Situational awareness of Real-time system operations is enabled through monitoring and analysis tasks performed by operators. Existing and proposed TOP and IRO standards and definitions developed in

SAR Information
Project 2014-03 Revisions to TOP and IRO Standards require Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed project will provide additional reliability benefits by addressing issues with the availability and information quality of Real-time monitoring and analysis capabilities. Specifically, the SDT will develop requirements and definition(s), as needed, to accomplish the following: • Establish a common understanding of *monitoring* as it applies to Real-time situational awareness of the Bulk Electric System (BES), • Provide operators with indication(s) of the quality of information being provided by *monitoring* capabilities and procedure(s) to address data quality issues, • Provide operators with notification(s) during unplanned loss of *monitoring* capabilities, • Provide operators with indication(s) of the quality of information being provided by *analysis* capabilities and procedure(s) to address analysis quality issues, and • Provide operators with notification(s) during unplanned loss of *analysis* capabilities. When completed, the project will have addressed recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	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 a Balancing Authority Area and supports Interconnection frequency in real time.

Reliability Functions		
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	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 service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	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.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.

Reliability and Market Interface Principles	
☒	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.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power 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 power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power 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 of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability 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
Project 2014-03 Revisions to TOP and IRO Standards	Proposed TOP and IRO standards and definitions from Project 2014-03 require RC, TOP, and BAs to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed standards and definitions are pending regulatory approval.

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Unofficial Comment Form

Project 2009-02 Real-time Monitoring and Analysis Capabilities

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the Standards Authorization Request (SAR) developed by the SAR Drafting Team (SAR DT). The electronic comment form must be completed by **8:00 p.m. Eastern, Monday, August 17, 2015**.

Documents and information about this project are available on the project page. If you have any questions, contact Standards Developer, Mark Olson (via email), or at (404) 446-9760.

Background Information

In April 2015, the Standards Committee (SC) appointed a new SAR DT to resume development on Project 2009-02 Real-time Monitoring and Analysis Capabilities. This project originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) but was paused in 2011. In determining the recommended scope for standards development, the SAR DT reviewed previous work associated with this project along with recommendations from the 2008 RTBPTF report, FERC Order No. 693 directives, and recommendations from the 2011 Southwest Outage Report. Additionally, an industry technical conference was conducted on June 4, 2015, to solicit feedback and recommendations from industry stakeholders.

The proposed project will develop requirements and definition(s), as needed, for Real-time monitoring and analysis capabilities to ensure effective operator situational awareness. Existing and proposed TOP and IRO standards and definitions from Project 2014-03 Revisions to TOP and IRO Standards require Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) to perform monitoring and analysis to maintain reliable operations. Project 2009-02 will provide additional reliability benefits by addressing issues with the availability and information quality of Real-time monitoring and analysis capabilities as described in the SAR and supporting white paper.

Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. Do you agree with the proposed scope for Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

☐ Yes
☐ No
Comments:

2. Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.
Comments:

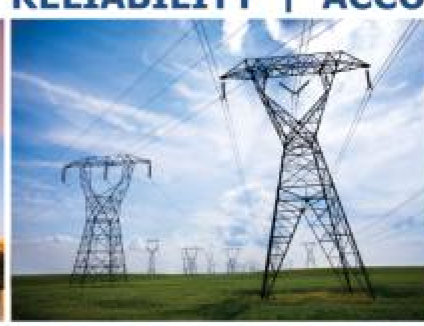
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Justification

Project 2009-02 Real-time Monitoring and Analysis Capabilities

RELIABILITY | ACCOUNTABILITY



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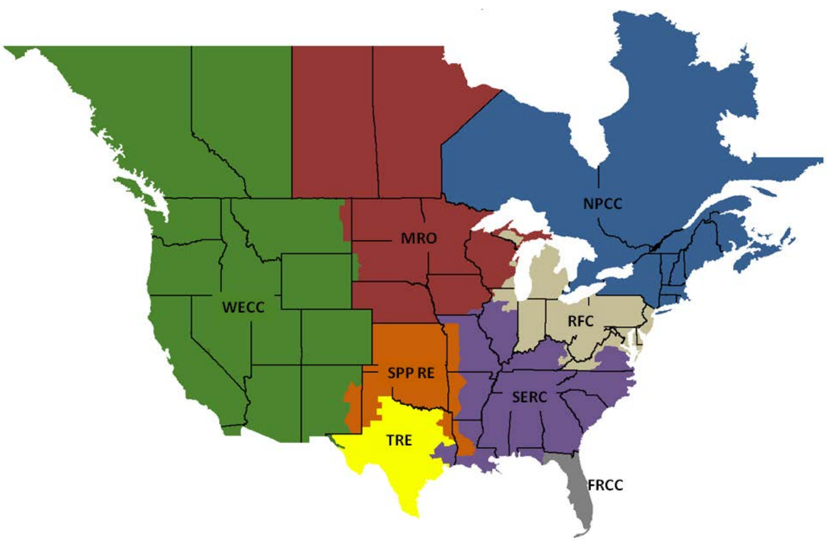
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

In April 2015, the Standards Committee appointed a new Standards Authorization Request (SAR) Drafting Team (SAR DT) for Project 2009-02 Real-time Monitoring and Analysis Capabilities. This project originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). Several new Reliability Standards and defined terms have been approved or filed for approval in the years since Project 2009-02 was initiated, including the standards developed in Project 2014-03 Revisions to TOP and IRO Standards. As a result, many of the original issues identified by the RTBPTF for Project 2009-02 have been addressed. In addition, relevant observations and recommendations have emerged from more recent events on the Bulk Electric System (BES) and operating practices have evolved over time. The SAR DT has reviewed previous work done in Project 2009-02, new standards and defined terms, relevant industry report findings and recommendations including those contained in the 2011 Southwest Outage report, and industry observations and practices relevant to real-time situational awareness to assist in developing a comprehensive SAR.

This white paper describes the SAR DT's approach to developing the SAR and discusses the technical basis for developing Reliability Standards in Project 2009-02. This white paper and the associated SAR together are intended to fully describe the project purpose, industry need, and project scope.

Chapter 1 – Background

FERC Order No. 693[1] highlights the need for a minimum set of capabilities to be available to assist operators in making real-time decisions. The work done by the RTBPTF, which was formed by NERC in response to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, became the basis for the Real-time Monitoring and Analysis Capabilities (RTMAC) standards development project when it was initiated in 2009. Although Reliability Standards affecting the operating reliability of the Bulk Electric System (BES) have improved significantly over the years since first becoming mandatory in 2007, a reliability issue has persisted in the area of real-time situational awareness capabilities as highlighted in BES event reports and an independent review of the NERC Reliability Standards. A review of industry reports and recommendations pertaining to real-time monitoring and analysis capabilities is provided in this document and in the Appendix. These recommendations, along with the FERC Order No. 693 directives, describe the industry need for the current RTMAC standards project.

BES Event Reports

Project 2009-02, like some other Reliability Standards projects, is informed by the lessons learned from past outages. The two significant outages discussed below highlight issues in real-time situational awareness, among other reliability concerns. Many Communications (COM), Transmission Operations (TOP), and Interconnection Reliability Operations (IRO) standards have addressed event report recommendations to improve the way the BES is planned and operated. The scope of Project 2009-02 is intended to include remaining recommendations from the 2003 Blackout Report and the 2011 Southwest Outage Report that pertain to real-time monitoring and analysis capabilities.

2003 Blackout Report

The largest blackout in history to affect North America began on the afternoon of August 14, 2003 and disrupted over 61,800 Megawatts of electric load in the Northeastern U.S. and the Canadian province of Ontario. Severe impacts to electrical service lasted for nearly one week and an estimated 50 million people were affected. A comprehensive investigation conducted by U.S. and Canadian government and industry leaders identified a host of principal and contributing causes, including:

- Failure to maintain adequate reactive power support,
- Failure to ensure operation within secure limits,
- Inadequate vegetation management,
- Inadequate operator training,
- Failure to identify emergency conditions and communicate that status to neighboring systems, and
- Inadequate regional-scale visibility over the Bulk-Power System (BPS).

Among other causes, the 2003 blackout was linked to dysfunction of SCADA/EMS systems. Additionally, investigators pointed out that several deficiencies leading to the 2003 blackout were also identified weaknesses in previous outages, indicating the need for more effective response. Previous post-event reports included recommendations aimed at improving capabilities for visualizing changes to facilities within the system, and for visualizing changes to facilities in neighboring systems that could have a potential impact. A recurring recommendation also focused on providing capabilities for operators to evaluate courses of action. These

[1] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, 72 Fed. Reg. 16416 at P 1660 (Apr. 4, 2007), FERC Stats. And Regs.¶ 31,242, *order on reh'g,* Order No. 693-A, 120 FERC ¶ 61,053 (2007) (Order No. 693).

observations led to the recommendation in the final report of the 2003 blackout for NERC to **evaluate and adopt better real-time tools for operators and reliability coordinators.**[2]

In response, the NERC Operating Committee organized the RTBPTF to study the real-time situational awareness practices in use within the electric power industry and make recommendations concerning the establishment of minimum capabilities necessary for reliable operations. The RTBPTF report *Real-time Tools Survey Analysis and Recommendations,*[3] completed in 2008, is the result of extensive information gathering and analysis and includes recommendations for new or enhanced Reliability Standards, operating guides, and areas for further analysis. This report became a basis for initiating the Real-time Monitoring and Analysis Capabilities project in 2009.

Although exhaustive and comprehensive, some of the RTBPTF recommendations go beyond the scope of situational awareness monitoring and capabilities. In addition, many other recommendations have been addressed in other subsequent standards projects. The appendix provides a description of RTBPTF report recommendations and the SAR DT's determination of applicability within the scope of Project 2009-02.

An early Concept White Paper describing potential performance, availability, quality, and maintenance parameters based on the RTBPTF Report was developed in 2011. The SAR DT reviewed the white paper and confirmed that, due to significant changes to Reliability Standards and operating practices since it was drafted, the 2011 Concept White Paper is no longer relevant to the current effort in Project 2009-02.

2011 Southwest Outage Report

Like the 2003 blackout in the northeast, the blackout that occurred in the southwest in September 2011 was partly due to, or exacerbated by, inadequate real-time situational awareness. On the afternoon of September 8, 2011, the loss of a single 500 kV line led to widespread cascading outages affecting 2.7 million customers in Arizona, Southern California, and Baja, Mexico. Inadequate operations planning was a significant factor in the failure to maintain a secure N-1 state. However, the report also highlighted several concerns with entities and their ability to monitor, identify, and plan for the next most critical contingency in real-time.[4]

Project 2014-03 - Revisions to TOP and IRO Standards addressed many of the recommendations contained in the 2011 Southwest Outage Report related to operations planning and real-time situational awareness. A complete description is provided in the Southwest Outage Report mapping document for Project 2014-03.[5] Revised definitions and performance requirements for Real-time Assessments and Operational Planning Analysis and proposed requirements for developing and implementing Operating Plans to prevent and mitigate operating limit exceedances address most of the real-time situational awareness recommendations from the report. However some recommendations contain aspects pertaining to real-time capabilities that should be considered in Project 2009-02, as described in the appendix. Accordingly, Project 2009-02 will develop requirements to address remaining recommendations as described in the following chapter.

[2] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* Recommendation 22, available at http://www.nerc.com/pa/rrm/ea/2003%20Blackout%20Final%20Report/Forms/AllItems.aspx.

[3] *Real-Time Tools Survey Analysis and Recommendations* (March 13, 2008), available at http://www.nerc.com/comm/OC/Realtime%20Tools%20Best%20Practices%20Task%20Force%20RTBPTF%2020/Real-Time%20Tools%20Survey%20Analysis%20and%20Recommendations.pdf.

[4] *Arizona-Southern California Outages on September 8, 2011* (April 2012), available at http://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf.

[5] See the project page for 2014-03, available at http://www.nerc.com/pa/stand/pages/project-2014-03-revisions-to-top-and-iro-standards.aspx.

FERC Directives

In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to operators.[6] FERC indicated that the intent of the directive is to ensure operating entities have adequate tools to perform their real-time reliability functions.[7]

- P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.*
- P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.*
- P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.*

Independent Experts Review Project (IERP) Report

In 2013, NERC retained a team of five industry experts to assess the quality of the enforceable body of standards and make recommendations for improvements that could be implemented by NERC and the industry.[8] Among the recommendations made by the panel of experts was the identification of potential risks to reliability that may not be adequately addressed in Reliability Standards. The report recommended resuming development of the Real-time Monitoring and Analysis Capabilities standards project.

Proposed TOP and IRO Standards

Since Project 2009-02 was initiated in 2009, many standards and definitions have been revised or developed that address real-time situational awareness issues. In particular, the revised TOP and IRO standards in Project 2014-03, which are pending regulatory approval, include key provisions for real-time situational awareness and operations planning. In reviewing the RTBPTF report recommendations for applicability in the current Project 2009-02 effort, the SAR DT considered the Project 2014-03 standards as noted in the Appendix.

The proposed TOP and IRO standards in Project 2014-03 provide requirements for performing monitoring and analysis through the definition of Real-time Assessment, Operational Planning Analysis, and the relevant requirements. Accordingly, additional requirements to perform monitoring or analysis will not be included in the scope for Project 2009-02. Furthermore, requirements for data exchange to support real-time monitoring and analysis will not be included in scope for Project 2009-02 because they are addressed through data specification requirements in IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3.

[6] Order No. 693 at P 905 (approving IRO-002-1 and directing modifications) and P 1665 (approving TOP-006-1 and directing modifications.

[7] Additionally, in approving VAR-001-1 - Voltage and Reactive Control, the Commission directed NERC to develop modifications to the standard to require periodic performance of voltage stability analysis to assist in real-time operations. The commission clarified that this could be accomplished through online tools where available, or offline simulation tools.

- §1875: *...[w]e direct the ERO, through its Reliability Standards development process, ...to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.*

VAR-001 was revised in the Project 2013-04, however the revised standard did not include a requirement for periodic performance of voltage stability analysis because voltage stability analysis is performed per SOL Methodology developed under FAC standards.

[8] See The Standards Independent Experts Review Project report. Available at www.nerc.com /pa/Stand/_layouts/xlviewer.aspx?id=/pa/Stand/Documents/P81_and%20IERP_Recommendations_for_Retirement_010815.xlsx.

Technical Conference

NERC and the SAR DT held a Technical Conference in Atlanta on June 4, 2015, to obtain industry input on reliability issues to be addressed in the proposed project. Participant subject matter experts representing a diverse mix of regional and functional entities shared their perspectives on the use of real-time situational awareness capabilities for reliable operations. There was consensus that many RTBPTF recommendations have been addressed in current or proposed TOP and IRO standards. However, Technical Conference participants agreed that issues identified by the RTBPTF pertaining to availability and information quality of real-time monitoring and analysis capabilities were still relevant.

Chapter 2 – Project Scope

The SAR DT has reviewed all recommendations from the RTBPTF and relevant recommendations from event reports, along with the existing body of standards, to identify remaining issues that should be in the scope for Project 2009-02. Table 1 below shows the resulting recommendations to be addressed. Additionally, the project will address outstanding FERC directives discussed in the preceding chapter.

Table 1: Report Recommendations to Address in Project 2009-02

Source	Recommendation	Discussion	Applicable Entity
2003 Blackout Report	Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators.	Project 2009-02 will develop requirements for real-time reliability monitoring and analysis capabilities to address issues not already addressed in other Reliability Standards. RTBPTF report recommendations will be considered in development.	RC, TOP, BA
2011 Southwest Outage Report	Recommendation 12 - [entities] should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2009-02 will develop requirements to improve the adequacy and operation of real-time monitoring and analysis capabilities. Requirements addressing the frequency that real-time tools run are contained in other standards and are not in the scope of this project.	RC, TOP, BA
RTBPTF Report	S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • Alarm Tools • Telemetry Data Systems • Network Topology Processor • State Estimator • Contingency Analysis	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. Prescription of specific tools is not in scope. Project approach is discussed below.	RC, TOP, BA as discussed below
RTBPTF Report	S7 - S8, S11-S12, S40 - Availability of various monitoring and analysis capability processes	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and analysis capabilities are not available (i.e., not performing their intended function).	RC, TOP, BA

Project Purpose and Approach

Project 2009-02 will develop requirements for real-time monitoring and analysis capabilities used by operators in support of reliable System operations. Functional requirements for performing *monitoring* and *analysis* tasks are well established in Reliability Standards as discussed throughout this white paper. However, reliability could be improved by:

- Developing a common understanding of *monitoring* as it applies to real-time situational awareness of the BES,
- Providing operators with indication(s) of the quality of information being provided by *monitoring* and *analysis* capabilities, and

- Providing operators with notification(s) during unplanned loss of *monitoring* and *analysis* capabilities.

Project 2009-02 will develop requirements and definition(s), as needed, to accomplish these reliability objectives as discussed.

Real-time Situational Awareness Concept

From the RTBPTF Report:

> *Situational awareness, as RTBPTF understands it, means ensuring that accurate information on current system conditions, including the likely effects of future contingencies, is continuously available in a form that allows operators to quickly grasp and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations.*

The Project 2009-02 SAR DT believes that situational awareness encompasses two broad capabilities: monitoring and analysis. To be effective in supporting real-time situational awareness, monitoring and analysis must:

- Be performed with sufficient frequency to allow operators to understand operating conditions and take corrective actions when necessary,
- Provide awareness of information quality to allow operators to assess the accuracy of information being received on system conditions and take corrective actions when necessary, and
- Indicate when monitoring or analysis processes are not operating normally or are unavailable in order to provide operator awareness of the accuracy of the information being provided.

Project 2009-02 will develop new requirements and definition(s), as needed, that support this concept of situational awareness without duplicating aspects that are already addressed in the existing and proposed body of Reliability Standards. As discussed in the preceding chapter, requirements for the Reliability Coordinator (RC), Transmission Operator (TOP), and Balancing Authority (BA) to perform monitoring and analysis are covered under existing and proposed TOP and IRO standards. Therefore, Project 2009-02 will focus on developing requirements to address information quality and operator awareness of real-time monitoring and analysis capabilities. Table 2 shows reliability objectives that should be addressed in requirements for this project.

Monitoring

Monitoring BES facilities in real-time is a primary function of the RCs, TOPs, and BAs and is addressed in existing and proposed TOP and IRO standards. For RCs, proposed IRO-002-4 states:

> *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.*

For TOPs and BAs, proposed TOP-001-3 states:

> *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.

The SAR DT understands *monitoring* capabilities may include both alarming and information visualization. Project 2009-02 will aim to develop a consistent understanding of *monitoring* within the industry. The project will also address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of information being provided by a monitoring system, and indication when a monitoring system is not operating normally.

Analysis

The *analysis* component of the Real-time situational awareness concept is described by the definition of Real-time Assessment, which is pending FERC approval along with the proposed TOP and IRO standards. The proposed definition is as follows:

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.)*

Requirements for performing Real-time Assessments are contained in proposed IRO-008-2 and TOP-001-3:

Proposed IRO-008-2
R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed TOP-001-3
R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

The SAR DT believes the proposed definition of Real-time Assessment and the requirements in proposed IRO-008-2 and TOP-001-3 provide RCs and TOPs with flexibility to determine which real-time tools, such as State Estimator, Contingency Analysis, and Stability Applications, are necessary to meet their real-time reliability functions. Consequently, prescriptive requirements for real-time tools are not in scope for Project 2009-02.

The project will address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of the analysis provided by a Real-time Assessment and notification when Real-time Assessment capabilities are not available.

Table 2: Project 2009-02 Reliability Objectives		
	Monitoring Capabilities	**Analysis Capabilities**
Quality	Provide operator with indication of information quality and procedures to address data quality issues.	Provide operator with indication of information quality and procedures to address analysis quality issues.

Availability	Provide operator with notification any time monitoring system is not operating normally.	Provide operator with notification any time Real-time Assessment capabilities are not available.

Appendix – Report Recommendations

The table below contains recommendations for improved real-time situational awareness capabilities found in relevant industry reports and how these recommendations have been addressed, if applicable. If recommendations have not been addressed fully, the table includes a description of how they should be addressed in Project 2009-02. The following industry reports are considered here[9]:

- 2003 Blackout Final Report
- 2011 Southwest Outage Report
- Real-time Tools Best Practices Task Force

Report Recommendation Mapping	
Report Recommendation	**Applicable Standard(s)**
2003 Blackout Final Report	
Recommendation 1-21, 23-46	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators. Operating Committee to evaluate the real-time operating tools necessary for reliability operation and reliability coordination, including backup capabilities. The committee's report is to address both minimum acceptable capabilities for critical reliability functions and a guide to best practices.	The Operating Committee established the RTBPTF to evaluate real-time operating tools and make recommendations for proposed standards. Project 2009-02 should consider these recommendations as discussed below.
2011 Southwest Outage Report	
Recommendation 1-10, 13-26	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 11 - TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Project 2014-03 developed the proposed definition of Real-time Assessment and proposed TOP-003-3 Requirement R1 which describes the requirements for a data specification that will provide all of the data that a TOP needs in order to fulfill its reliability function. Together, these address capabilities and required data TOPs must have to ensure adequate situational awareness. **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.) **Proposed TOP-003-3, Requirement R1, Part 1.1**:

[9] *All industry reports are available on the 2009-02 Project Page: http://www.nerc.com/pa/Stand/Pages/Project-2009-02-Real-time-Reliability-Monitoring-and-Analysis-Capabilities.aspx.*

	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.
Recommendation 12 - TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2014-03 developed a requirement for the performance of a Real-time Assessment for Transmission Operators. Standards developed in Project 2009-02 will address the adequacy of tools as described in this recommendation. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
Recommendation 27 - TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences.	Proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA) developed in Project 2014-03 specify that identified phase angle limitations must be considered and deal with applying phase angle information. Proposed TOP-002 Requirement R2 specifies that TOPs must have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified in the OPA. Data specification requirements in approved IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3 provide a means for RCs and TOPs to obtain phase angle information. **Proposed Definition: 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.) **Proposed Definition: 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.) **Proposed TOP-002-4** 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.
RTBPTF Report	
S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • **Alarm Tools** • **Telemetry Data Systems** • **Network Topology Processor** • **State Estimator** • **Contingency Analysis**	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. However, prescription of specific tools is not in scope.
S2 - Compile and maintain a list of all bulk electric system elements within RC's area of responsibility.	Not in scope. Reliability objective is accomplished through monitoring and analysis requirements as discussed below.
S3 - Add new requirements and measures pertaining to RC monitoring of the bulk electric system.	Addresses in IRO standards (current and proposed). **IRO-002-2** R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. **IRO-003-2** R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. **Proposed IRO-002-4** 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.
S4 - Develop data-exchange standards.	Addressed in proposed TOP-001-3 and IRO-002-4. **Proposed TOP-001-3** R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area. R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it

	needs data from in order to maintain reliability in its Balancing Authority Area. **Proposed IRO-002-4** 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.
S5 - Develop data-availability standards and a process for trouble resolution and escalation.	Data availability and trouble resolution is addressed in IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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.
S6 - Develop a new weather data requirement related to situational awareness and real-time operational capabilities.	EOP-010-1 covers space weather dissemination. The SAR DT views monitoring other weather information as common utility practice that does not require a reliability standard.
S7 - Specify and measure minimum availability for alarm tools.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the

	RTBPTF report to provide operator awareness when key monitoring, alarming, and analysis tools are not available (i.e. not performing their intended function).
S8 - Specify and measure minimum availability for network topology processor.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring, alarming, and analysis tools are not available (i.e. not performing their intended function).
S9 - Establish a uniform formal process to determine the "wide area view boundary" and show boundary data/results.	Wide-area is now a defined term. Recommendation has been addressed.
S10 - Develop compliance measures for verification of the usage of "wide-area overview display" visualization tools.	IRO standards revisions have addressed compliance measures.
S11 - Specify and measure minimum availability for state estimator, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring, alarming, and analysis tools are not available (i.e. not performing their intended function).
S12 - Specify and measure minimum availability for contingency analysis, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation to provide operator awareness when key monitoring, alarming, and analysis tools are not available (i.e. not performing their intended function).
S13 - Specify criteria and develop measures for defining contingencies.	Not in scope; Addressed in approved TPL and FAC standards.
S14 - Perform one-hour-ahead power-flow simulations to assess approaching SOL and IROL violations and corresponding measures.	Requirements for assessing pre- and post-contingency system conditions are addressed in Real-time Assessment (RTA) and Operational Planning Analysis (OPA) definitions. Requirements for performing RTA and OPA are contained in proposed TOP-001-3, TOP-002-4, IRO-008-2, and approved IRO-008-1. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2**

	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. R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed definition** **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.) **Proposed definition** **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.)
S15 - Provide real-time awareness of load-shed capability to address potential or actual IROL violations.	Addressed in proposed EOP-011-1, approved IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-

	reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

	IRO-010-1 R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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.
S16 - Require BAs to monitor contingency reserves and calculate contingency reserves at a minimum periodicity of 10 seconds.	BA responsibilities for managing Contingency Reserve are addressed in the approved BAL-002-1 standard which is under revision in Project 2010-014. 1. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.
S17 - Revise the current-day operations requirements to delineate specific, independent requirements for monitoring operating and reactive reserves.	Addressed in VAR-001-4, BAL-002, and proposed IRO-002-4 and TOP-001-3. **VAR-001-4** R4. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary.

	BAL-002-1 R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. **Proposed IRO-002-4** **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. **Proposed TOP-001-3** 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.
S18 - Establish document plans and procedures for conservative operations.	Addressed in proposed EOP-011-1 Requirement R1. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies

	and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
S19 - Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes.	Addressed in proposed TOP-001-3, and IRO-008-2 and the proposed definitions for Operational Planning Analysis and Real-time Assessment. **Proposed TOP-001-3** R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. 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 an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-008-2** 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. **Proposed definition** **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.) **Proposed definition** **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.)
S20 - Develop formal operating guides (mitigation plans) and measures for each IROL and any SOL or other conditions having a potential impact on reliability.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S21 - Review and update operating guides (mitigation plans) when day-ahead or current day studies indicate the potential need to implement an operating guide.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S22 - Provide temporary operating guides (mitigation plans) with control actions for situations that could affect reliability but that have not been identified previously.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S23 - Develop joint operating guides (mitigation plans) for situations that could require more than one RC or more than one TOP to execute actions.	Addressed in IRO-014-2, proposed IRO-014-3 and proposed IRO-008-2. **IRO-014-2** R1. Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall collectively address the following: ... **Proposed IRO-014-3** 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: ... **Proposed IRO-008-2** 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.
S24 - Develop a formal procedure to document the processes for developing, reviewing, and updating operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S25 - Incorporate verifiable and traceable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates when modifying operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S26 - Write operating guides (mitigation plans) in clear, unambiguous language, leaving nothing to interpretation.	Not in scope. This is administrative in nature.
S27 - State the specific purpose of existence for each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S28 - Summarize the specific situation assessment and address the method of performing the assessment in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S29 - Identify all appropriate preventive and remedial control actions in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S30 - Develop criteria in operating guides (mitigation plans) to support decisions regarding whether a specific control action should be taken.	Not in scope. This is administrative in nature.
S31 - Incorporate on-line tools that utilize on-line data when operating guides (mitigation plans) require calculations.	Not in scope. Recommendation is appropriate as a guideline rather than a reliability standard.

S32 - Make operating guides (mitigation plans) readily available via a quick-access method such as Web-based help, EMS display notes, or on-line help systems.	Not in scope. This is administrative in nature.
S33 - Provide the location, real-time status, and MWs of load available to be shed.	Addressed in proposed EOP-011-1 Requirement R1 Part 1.2.5 and proposed TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. **Proposed TOP-003-3** 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. ...
S34 - Establish documented procedures for the reassessment and re-posturing of the system following an event.	Addressed in proposed TOP-002-4 and IRO-008-2, and approved EOP-005-2 and EOP-006-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses:

	4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ... **EOP-006-2** R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S35 - Provide information to operators to maintain awareness of the availability and capability of the blackstart generators and transmission restoration paths.	Addressed in approved IRO-010-1, proposed TOP-003-3, proposed IRO-010-2, approved EOP-005-2, and approved EOP-006-2. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability,

	uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... R1.6. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ... R1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit. ... R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known

	changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **EOP-006-2** R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S36 - Plan and coordinate scheduled outages of blackstart generators and transmission restoration paths.	Addressed in approved EOP-005-2 and proposed IRO-017-1 - Outage Coordination. **EOP-005-2** R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **Proposed IRO-017-1** R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: ...
S37 - Maintain a Critical Equipment Monitoring Document to identify tools and procedures for monitoring critical equipment.	Not in scope. This is administrative in nature.
S38 - Maintain event logs pertaining to critical equipment status for a period of one year.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be "installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools". Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S39 - Maintain a Critical Equipment Maintenance and Testing Document identifying tools and procedures for maintenance, modification, and testing of critical equipment.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be "installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools". Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.

S40 - Monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation.	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and analysis capabilities are not available (i.e., not performing their intended function).

Standards Announcement

Project 2009-02 Real-time Monitoring and Analysis Capabilities Standard Authorization Request

Formal Comment Period Open through August 17, 2015

Now Available

A 30-day formal comment period for the **Project 2009-02 Real-time Monitoring and Analysis Capabilities** Standard Authorization Request (SAR) is open through **8 p.m. Eastern, Monday, August 17, 2015.**

Commenting

Use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Mark Olson (via email) or at (404) 446-9760.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Survey Report

Survey Details

Name 2009-02 Real-time Monitoring and Analysis Capabilities SAR

Description

Start Date 7/16/2015

End Date 8/17/2015

Associated Ballots

Survey Questions

1. Do you agree with the proposed scope for Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Yes

No

Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.

Responses By Question

1. Do you agree with the proposed scope for Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

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

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

We agree with the need to establish the requirements for real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations. However, we believe such requirements do not rise up to the level of Reliability Standards, whose objective is to drive the proper behaviors that contribute to reliability.

We believe real-time monitoring and analysis capabilities are the "one-off" type that is required for performing a registered entity's functions. Such capabilities need to be provided and tested at the organization certification stage, and in subsequent verification stages. Another example of this type of requirement is the provision of redundant communication facilities, or the installation of disturbance monitoring devices.

Therefore, we do not support this SAR, and propose that the requirements for providing the real-time monitoring and analysis capabilities be stipulated in the concerned functional entities' organization certification requirement.

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

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: Yes

Answer Comment:

The NSRF is aware of the Commission directives and past outage reports that have set the foundation for this project. Taken singularly (looking at these objectives, only) this Project should be rather straight forward. But as the SDT knows, the newly developed Requirements will be in addition to the real-time responsibilities that (System) operators have currently, in maintaining a balanced and secure system.

The NSRF wishes to remind the SDT that awareness (within Situational Awareness) should not turn into Situational Assurance (beyond a doubt). That *awareness* is "*knowing*" that something exist that may impact you and not necessarily having an *in depth understanding* of the root cause and effect of the situation. As an example, a TOP has a 345kV line trip and lock out. The TOP should have an *in depth understanding* of how the megawatt flows of their system will change when this lock out occurs. The impact BA Area does not need to *know* much beyond that the line has tripped, but rather needs the awareness that they may be called upon to help reconfigure their system (re-dispatch generation, shed load, etc.).

All Requirements (present and future) cannot remove the possibility of human error. A contributing factor to human error is data overload (ie, alarms [actual and false] communications [phone call, radio call, blast calls], processing this tremendous amount of information, having information constantly in a state of change and being compliant with ALL currently enforceable Standards. Note that System Operators have a higher tendency to make mistakes when their systems are stressed and usually in an emergency condition (either a capacity or transmission emergency). Not that their tools failed them but rather the most critical element or system condition wasn't mitigated first. The SDT must remain aware to *complexity creep* and look at ALL real-time operator responsibilities when developing this project and that adding new responsibilities may be detrimental to system reliability..

The NSRF looks forward to working with the SDT on this Project.

Note: We have progressed and are now aware of systems and conditions since the 2003 Blackout. Please consider this. Tools should be used as a "control" within an entity's Risk Assessment.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NA - Not Applicable

Group Information

Group Name: Standards Review Committee (SRC)

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Matthew Goldberg	ISO-NE	NPCC	2
Christina Bigelow	ERCOT	TRE	2
Terry Bilke	MISO	MRO	2
Al Dicaprio	PJM	RFC	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter	Segment
Kathleen Goodman	2
Entity	**Region(s)**
ISO New England, Inc.	NA - Not Applicable

Selected Answer: No

Answer Comment:

This proposed project appears to be well-suited for a guideline document as opposed to a Standard. As written, the SAR appears to intend to write a "how" not "what" Standard (*i.e.*, it does not appear to be a results-based standard). The SRC believes that the existing Standards (*i.e.*, IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (*i.e.*, without defining the "how"), which is appropriate. In the alternative, this could be considered a process to be used for Certifying new entities for assurance that they have the ability to monitor appropriately in accordance with the Standards Requirements.

The SRC notes that the tools available to operators have progressed well beyond those available in 2003. If defined tools would have been hardcoded in a standard at that time, it would have limited focus and investment to those things that were in the standard. Further, expanding on our point above, the SRC believes that the "what" regarding tools is more appropriately captured in the certification expectations for BAs, RCs, and TOPs. Additionally, it would be appropriate for Regions to evaluate tools as part of the Registered Entity's Inherent Risk Assessment (IRA). This would include the scope of tools, backups, etc. and would provide an adaptable approach that would encourage continuous improvement.

Additionally, the SRC recommends that NERC coordinate with the NATF to encourage inclusion of an ongoing "care and feeding" of tools evaluation and information sharing in their efforts with the provision that they make information on good practices available to the wider NERC community so that non-members can learn from the innovation of others.

Finally, to avoid these issues in the future and to support communicating to FERC when a Standard is not needed and another tool is more suitable, the SRC suggests that future SARs be voted on by industry to determine whether they should proceed as a Standards project or another means is a more appropriate method through which to achieve the SAR's objective.

Document Name:

Likes: 1 Tri-State G and T Association, Inc., 1,3,5, Banuelos Sergio

Dislikes: 0

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

The SAR has the "NEW" Standard box checked but not the "Revision to existing Standard" box. Based on the statement below from the SAR,
FirstEnergy feels the "Revision to existing Standard" should be checked also so other Standards can be included if necessary..

- P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.*

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT supports the SRC's comments regarding the proposed SAR, but - should the SAR proceed - would urge the SDT to ensure that the focus remains on what needs to be done - not how it should be done.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: No

Answer Comment:

How does NERC's Project 2009-02 differ from the work about to begin in the NERC Synchrophasor Measurements Subcommittee (SMS)? Should this project be part of SMS? In my mind ther is a great deal of overlap between the new SMS and Project 2009-02 and to a large extent, Project 2009-2 is dependent on the work to be done by SMS. Entergy recommend a delay or no vote on this project until SMS work is completed.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

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 2009-02

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: Yes

Answer Comment:

Suggest revising the Purpose to make it more encompassing. Suggest the following wording:

To establish situational awareness capabilities with results-based requirements for monitoring and analysis used by System Operators in support of reliable Real-time System operations.

The concepts being proposed in the scope of the SAR can be realized by revising the appropriate TOP and IRO standards by either revising existing requirements, or adding requirements. A new standard may not be necessary. Therefore, the SAR should provide the Drafting Team with the flexibility to add requirements to IRO-010-2 and TOP-003. For example, Requirement R2 in IRO-010-2 stipulates that:

“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.”

This requirement satisfies both the posted Purpose of the SAR:

“To establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations.”

and our suggested revision above.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer: Yes

Answer Comment:

We agree with the overall scope of the SAR. However, we do have a two concerns to address.

First, the SAR indicates that it will address all recommendations of the RTBPTF while the SAR Justification indicates that not all recommendations will be implemented. If by “addressing the recommendations” the SAR indicates that recommendation will considered based on its merits, we agree. Furthermore, we agree with the disposition of the vast majority of the recommendations as written in the SAR justification.

Second, if a “common understanding of *monitoring*” means a definition will be developed, we caution the drafting team to conduct a complete wholesale review of all NERC reliability standards to be sure the definition would not change the meaning of other requirements or cause confusion on applicability of the definition.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Hydro One Networks, Inc. - 1,3 - NPCC

Selected Answer: Yes

Answer Comment:

Hydro One Networks Inc. would like to provide the following additional recommendations for the SDT's consideration:

1. The effort required to capture activities/best practices the majority of entities have already employed may be of value;

2. The standard does not appear to deliver the intended future direction for system monitoring and ways to achieve this;

3. By the nature and competitiveness of the MS industry, providers will continue to develop and offer new functionalities that may or may not be desirable for every entity. The effort would be better suited to standardize requirements and allow for the industry to catch up to a common standard. In other words, this effort would provide minimal benefit for entities that already have a modern EMS and for others a large change to meet current requirements;

4. The goal should be to level-off the playing field and have all entities reach the same level of monitoring first.

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
John Allen	City Utilities of Springfield	SPP	1,4
Jason Smith	Southwest Power Pool Inc	SPP	2
Kevin Giles	Westar Energy,Inc.	SPP	1,3,5,6
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5

Mike Kidwell	Empire District Electric Company	SPP	1,3,5
Jess Gray	Omaha Public Power District	MRO	3
James "Jim" Nail	City of Independence, Missouri	SPP	3,5
Sing Tay	Oklahoma Gas and Elecric, Inc	SPP	1,3,5,6
Scott Williams	City Utilities of Springfield	SPP	1,4

Voter Information

Voter

Shannon Mickens

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

SPP

Selected Answer: No

Answer Comment:

Our review team believes that the standards process has resulted in a mature set of Reliability Standards that already fully address FERC Order 693. With that being said, we feel that there is no need for continuing efforts on this project for the fear of redundancy. We have concerns that the scope of the SAR could result in requirements that are redundant to other existing Standards and inappropriately set minimum capabilities based on a list of best practices. The SAR scope seems to focus on quality of information for entities in carrying out their adherence to other Standards. Additionally, we feel that perhaps the documentation of the entities capabilities should be captured in either the Rules of Procedure or other certification or registration procedures rather than in a Reliability Standard. Another option would be to include descriptions or clarification of those capabilities within the supporting documentation of the other Standards.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Texas RE noticed communicating results was not part of the SAR. Effective communications is part of situational awareness and can directly be related to the quality of information being provided as well as awareness of key monitoring and analysis capabilities. Monitoring and analysis capabilities should include communicating results to all entities requiring information. Is the SDT considering this type of communication? Texas RE is concerned the scope seems narrow. Has the SDT or NERC clearly identified all the recommendations and FERC directives have been thoroughly covered by the changes in all the relative Standards?

Texas RE acknowledges that FERC Order No. 693 mentioned that it did not wish to identify specific tools, but rather minimum capabilities. There are, however, standard industry tools for monitoring. Texas RE recommends the SDT consider making certain tools mandatory. Tools determine the status of reliability of the system. It seems as if the industry sees the need to call specific types of tools out but does not want the compliance aspects associated with the tools. State estimator and contingency analysis tool are extremely common utility practices to help ensure reliability. Is there a part of the BES that is not being monitored by a State Estimator or Contingency Analysis tool?

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: No

Answer Comment:

Tri-State Generation and Transmission supports the comments submit by the Standards Review Committee (SRC).

In addition, Tri-State also would like to add the following. Tri-State recognizes that Real-time situational awareness might have been a factor of the 2003 Northeast blackout and the 2011 Southwest blackout, however we believe that over the past four years there has been significant developments and improvement in the tools that operators have available particularly within the WECC region. Additionally, the recent bifurcation in the WECC region and the subsequent creation of a standalone Reliability Coordinator has led to significant improvements in regional coordination, operations, and overall system visibility. We believe the new TOP-003-1 standard directly addresses the 'what' leaving the 'how' up to the individual utility, specifically:

Requirement R10 for Monitoring power System data in Real-time (and TOP-003-3)
Requirement R13 for Determining the current state of the BES and Evaluating the impact of ‘what if’ events on the current state of the BES
Requirement R19 for Exchanging power System data in Real-time

Tri-State does not agree with the SAR and its intentions but should the SAR proceed we urge the SDT to better define the intentions of the SAR. Specifically Tri-State does not understand how the SDT intends to quantify acceptable “quality” without resulting in a subjective audit? Also what is included in the term “analysis capabilities” and how will these items be sufficiently quantified to allow for a consistent audit approach across the various Regional Entities?

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

In general, BPA agrees with the scope of the SAR, and conceptually with the effort to tie performance based metrics to real time situational awareness. BPA also agrees with the SAR DT, that the scope of the Project 2009-02 should avoid prescriptive assumptions regarding the implementation of real time tools by a specific entity.

As noted in the SAR Justification, real time situational awareness is closely associated with the pending definition of Real-time Assessment. BPA suggests that the concept of providing operators with notification of Availability, as described by the SAR DT, is already implied by the pending requirements in proposed TOP-001-3 R13 and IRO-008-2 R4.

TOP-001-3 R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

IRO-008-2 R4: Each Reliability Coordinator shall ensure that a Real□time Assessment is performed at least once every 30 minutes.

The process an entity develops to avoid a violation of these requirements will necessitate prompt notification any time the entity's ability to perform the Real Time Assessment is degraded. Additional requirements would therefore be either redundant or unnecessarily prescriptive.

BPA notes that a measurement of the **quality** of monitoring or analysis tools is likely to be closely dependent on the tools and processes implemented by the individual entity. However, BPA agrees with the SAR DT that ongoing assessment of the tools and processes implemented by an entity to perform Real-time Assessment is both necessary and a gap in the existing standards. It is important to avoid the pitfall of implicitly requiring a specific implementation for Real Time Assessment. Any new standards developed by Project 2009-02 must also allow the industry to continue developing and improving on the best practices described by the NERC Real Time Best Practice Task Force in 2008.

Therefore, BPA suggests that Project 2009-02 should only focus on developing requirements for entities to establish, based on their own local implementation, 1) procedures for evaluating the quality of their Real Time Assessment and the information needed to perform it, and 2) the processes for maintaining the quality of the required information to the performance thresholds the entity determines are necessary for performing the Real Time Assessment.

Document Name:

Likes: 0

Dislikes: 0

Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.

Thomas Foltz - AEP - 5 -

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

Leonard Kula - Independent Electricity System Operator - 2 -

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 wishes to point out that our industry has recently approved TOP-001-3 and it is currently pending approval from FERC. Specifically, R8, R10, R10.1, R10.2, R11, R12, R13, and R19 addresses several blackout recommendations concerning knowing how your system is performing and how to communicate mitigating actions to others. Please take this into consideration when developing this Standard.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

none

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NA - Not Applicable

Group Information

Group Name: Standards Review Committee (SRC)

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Matthew Goldberg	ISO-NE	NPCC	2
Christina Bigelow	ERCOT	TRE	2
Terry Bilke	MISO	MRO	2
Al Dicaprio	PJM	RFC	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Kathleen Goodman

Segment

2

Entity

ISO New England, Inc.

Region(s)

NA - Not Applicable

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer:

Answer Comment:

Entergy has the following additional comments: 1. When writing standards for issues that are technology driven, extreme care must be used to avoid arbitrarly increasing costs without commensurare increase in benefit to reliability. 2. Standards should be technology neutral to the extent possible. 3. Need a bright-line voltage level guidance for which these new requirements apply. Different entities have their own definition of what consitutes Transmission levels. There presently exists a range from 100 kV to 44 kV in our region. 4. Need a bright-line guidance regarding extent of external monitoring that needs to be performed. A specific number, for example 10% impact, on internal lines and transformers would be extremely helpful. Currently entities in our region monitor anywhere from 5% to 10% impact, if possible, or up to three buses away.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Xcel Energy has questions about any new standards or proposed revisions to existing standards that would result from this project. How stringent are the requirements going to be? Will fully redundant systems be required? Can a TOP rely on the RC or other entity as a temporary backup? What about if the RC goes down?

Additionally, we have concerns about the level of detail that would be required. We believe that a requirment to analyze contingencies on neighboring systems could cause undue burden on smaller systems with larger neighbors.

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2009-02

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)**

Selected Answer:

Answer Comment:

Any revisions made must not address the specifics of what the situational awareness capabilities are, but must focus on the adequacy of the monitoring and analysis.

This proposed project should be considered for a guideline document as opposed to a standard. As written, the SAR appears to intend to write a “how” not “what” standard (i.e. it does appear to be a results-based standard). We believe that the existing Standards (i.e. IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (i.e. without defining the “how”), which is appropriate.

As an alternative, this could be considered a process to be used for certifying new entities for assurance that they have the ability to monitor appropriately in accordance with the Standard’s Requirements.

To avoid these issues in the future and to support communicating to FERC that a standard is not needed but another tool is more suitable, we suggest the future SARs be voted on by industry as to whether to proceed as a Standards project or use another means to achieve the ends.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer:

Answer Comment:

2009-02 Real-time monitoring and analysis capabilities-S15 (Page 18 & 19), S18 (Page 21 and 22) and S33 (Page 26) all list EOP-011-1. EOP-011-1 is not effective due to not being approved by FERC. Although EOP-011-1 was written to consolidate EOP-001-2.1b, EOP-002-3.1 and EOP-003-2, we question if this project should be listing EOP-011-1 rather than the other 3 standards which are effective and approved.

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer:

Answer Comment:

There are two minor issues in the SAR Justification. On page 11, the last paragraph refers to Table 1. Yet, there is no Table 1. We assume Table 2 is supposed to be Table 1.

On page 15 regarding recommendation S3, “Addresses” should be “Addressed.”

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Hydro One Networks, Inc. - 1,3 - NPCC

Selected Answer:

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
John Allen	City Utilities of Springfield	SPP	1,4
Jason Smith	Southwest Power Pool Inc	SPP	2
Kevin Giles	Westar Energy,Inc.	SPP	1,3,5,6
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
Jess Gray	Omaha Public Power District	MRO	3
James "Jim" Nail	City of Independence, Missouri	SPP	3,5
Sing Tay	Oklahoma Gas and Elecric, Inc	SPP	1,3,5,6
Scott Williams	City Utilities of Springfield	SPP	1,4

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE agrees with the RTBPTF report which states "Develop a new weather data requirement related to situational awareness and real-time operational capabilities." The drafting team's response, "EOP-010-1 covers space weather dissemination. The SAR DT views monitoring other weather information as common utility practice that does not require a reliability standard", is concerning because registered entities might not monitor weather as they should. Weather is extremely pertinent to situational awareness and real-time operational capabilities. Weather has a significant impact and, too often, exacerbates reliability issues. If it is a common utility practice than successful compliance should not be an issue. Is the SDT considering a Guideline like what was done for the common utility practice of preparing a generator for winter operation?

Document Name:

Likes: 0

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

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment: N/A

Document Name:

Likes: 0

Dislikes: 0

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2009-02 Real-time Monitoring and Analysis Capabilities

Comment Period Start Date: 07/16/2015

Comment Period End Date: 08/17/2015

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) 446-2560.

Questions

1. **Do you agree with the proposed scope for Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.**
2. **Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.**

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. Do you agree with the proposed scope for Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Summary: The SDT thanks all commenters. Most commenters agree with the proposed scope for Project 2009-02. Some commenters raised concerns or provided recommendations that are summarized as follows:

- **Some commenters believe Project 2009-02 is not necessary, or that the reliability objectives should be addressed through the NERC Organization Certification Process.** The SDT maintains that the recommendations from BES event reports and the Real-time Tools Best Practices Task Force (RBPTF) Report that are referenced in the project SAR, as well as regulatory directives, establish the need for development of reliability standards. The SDT agrees that these capabilities should be demonstrated at the organization certification stage, but believes they should also be maintained on an ongoing basis through adherence to standards. Furthermore, development of standards is appropriate since, in general, organization certifications are based on the body of approved standards.

- **A commenter recommended modifying the SAR to indicate that the project could develop modifications to existing standards.** The SDT agrees that the project could either develop new standard(s) or modify existing TOP and IRO standards and modified the SAR accordingly.
- **A commenter noted notification of unavailability of analysis capabilities is implied in proposed TOP and IRO standards that are pending FERC approval.** The SDT agrees and modified the SAR to remove this reliability objective from Project 2009-02 scope.
- Several commenters provided recommendations for consideration during standards development.

Specific responses to all commenters are provided below.

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

We agree with the need to establish the requirements for real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations. However, we believe such requirements do not rise up to the level of Reliability Standards, whose objective is to drive the proper behaviors that contribute to reliability.

We believe real-time monitoring and analysis capabilities are the “one-off” type that is required for performing a registered entity’s functions. Such capabilities need to be provided and tested at the organization certification stage, and in subsequent verification stages. Another example of this type of requirement is the provision of redundant communication facilities, or the installation of disturbance monitoring devices.

Therefore, we do not support this SAR, and propose that the requirements for providing the real-time monitoring and analysis capabilities be stipulated in the concerned functional entities’ organization certification requirement.

Response: Thank you for your comment. The SDT believes that the recommendations from BES event reports and the RTBPTF Report that are referenced in the project SAR, as well as regulatory directives, establish the need for development of reliability standards. Project 2009-02 has been scoped to include recommendations and directives that have not been addressed in other standards. The SDT agrees that these capabilities should be demonstrated at the organization certification stage, and should also be maintained on an ongoing basis through adherence to standards. Development of standards is also appropriate since, in general, organization certifications are based on the body of approved standards.

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

Answer Comment:

The NSRF is aware of the Commission directives and past outage reports that have set the foundation for this project. Taken singularly (looking at these objectives, only) this Project should be rather straight forward. But as the SDT knows, the newly developed Requirements will be in addition to the real-time responsibilities that (System) operators have currently, in maintaining a balanced and secure system.

The NSRF wishes to remind the SDT that awareness (within Situational Awareness) should not turn into Situational Assurance (beyond a doubt). That *awareness* is "*knowing*" that something exist that may impact you and not necessarily having an *in depth understanding* of the root cause and effect of the situation. As an example, a TOP has a 345kV line trip and lock out. The TOP should have an *in depth understanding* of how the megawatt flows of their system will change when this lock out occurs. The impact BA Area does not need to *know* much beyond that the line has tripped, but rather needs the awareness that they may be called upon to help reconfigure their system (re-dispatch generation, shed load, etc.).

All Requirements (present and future) cannot remove the possibility of human error. A contributing factor to human error is data overload (ie, alarms [actual and false] communications [phone call, radio call, blast calls], processing this tremendous amount of information, having information constantly in a state of change and being compliant with ALL currently enforceable Standards. Note that System Operators have a higher tendency to make mistakes when their systems are stressed and usually in an emergency condition (either a capacity or transmission emergency). Not that their tools failed them but rather the most critical element or system condition wasn't mitigated first. The SDT must remain aware to *complexity creep* and look at ALL real-time operator responsibilities when developing this project and that adding new responsibilities may be detrimental to system reliability..

The NSRF looks forward to working with the SDT on this Project.

Note: We have progressed and are now aware of systems and conditions since the 2003 Blackout. Please consider this. Tools should be used as a "control" within an entity's Risk Assessment.

Response: Thank you for your comment.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Kathleen Goodman - ISO New England, Inc. - 2 - NA - Not Applicable

Group Name: Standards Review Committee (SRC)

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Matthew Goldberg	ISO-NE	NPCC	2
Christina Bigelow	ERCOT	TRE	2
Terry Bilke	MISO	MRO	2
Al Dicaprio	PJM	RFC	2
Ali Miremadi	CAISO	WECC	2

Selected Answer: No

Answer Comment:

This proposed project appears to be well-suited for a guideline document as opposed to a Standard. As written, the SAR appears to intend to write a “how” not “what” Standard (*i.e.*, it does not appear to be a results-based standard). The SRC believes that the existing Standards (*i.e.*, IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (*i.e.*, without defining the “how”), which is appropriate. In the alternative, this could be considered a process to be used for Certifying new entities for assurance that they have the ability to monitor appropriately in accordance with the Standards Requirements.

The SRC notes that the tools available to operators have progressed well beyond those available in 2003. If defined tools would have been hardcoded in a standard at that time, it would have limited focus and investment to those things that were in the standard. Further, expanding on our point above, the SRC believes that the “what” regarding tools is more appropriately captured in the certification expectations for BAs, RCs, and TOPs. Additionally, it would be appropriate for Regions to evaluate tools as part of the Registered Entity’s Inherent Risk Assessment (IRA). This would include the scope of tools, backups, etc. and would provide an adaptable approach that would encourage continuous improvement.

Additionally, the SRC recommends that NERC coordinate with the NATF to encourage inclusion of an ongoing “care and feeding” of tools evaluation and information sharing in their efforts with the provision that they make information on good practices available to the wider NERC community so that non-members can learn from the innovation of others.

Finally, to avoid these issues in the future and to support communicating to FERC when a Standard is not needed and another tool is more suitable, the SRC suggests that future SARs be voted on by industry to determine whether they should proceed as a Standards project or another means is a more appropriate method through which to achieve the SAR’s objective.

Response: Thank you for your comment. The SDT believes that the recommendations from BES event reports and the RTBPTF Report that are referenced in the project SAR, as well as regulatory directives, establish the need for development of reliability standards. Project 2009-02 has been scoped to include recommendations and directives that have not been addressed in other standards. The SDT agrees that approved and proposed standards define requirements for performing monitoring and analysis tasks as described in the SAR Justification White Paper, and that the proposed project should not define or prescribe specific tools. In addressing the issues and recommendations identified in the SAR, the SDT will develop appropriate results-based requirements. The SDT agrees that monitoring and analysis capabilities should be demonstrated at the organization certification stage, and should also be maintained on an ongoing basis through adherence to standards. Development of standards is also appropriate since, in general, organization certifications are based on the body of approved standards.

Likes: 1 Tri-State G and T Association, Inc., 1,3,5, Banuelos Sergio

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Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: No

Answer Comment:

1. Tri-State Generation and Transmission supports the comments submit by the Standards Review Committee (SRC).

2. In addition, Tri-State also would like to add the following. Tri-State recognizes that Real-time situational awareness might have been a factor of the 2003 Northeast blackout and the 2011 Southwest blackout, however we believe that over the past four years there has been significant developments and improvement in the tools that operators have available particularly within the WECC region. Additionally, the recent bifurcation in the WECC region and the subsequent creation of a standalone Reliability Coordinator has led to significant improvements in regional coordination, operations, and overall system visibility. We believe the new TOP-003-1 standard directly addresses the 'what' leaving the 'how' up to the individual utility, specifically:

Requirement R10 for Monitoring power System data in Real-time (and TOP-003-3)
Requirement R13 for Determining the current state of the BES and Evaluating the impact of 'what if' events on the current state of the BES
Requirement R19 for Exchanging power System data in Real-time

3. Tri-State does not agree with the SAR and its intentions but should the SAR proceed we urge the SDT to better define the intentions of the SAR. Specifically Tri-State does not understand how the SDT intends to quantify acceptable "quality" without resulting in a subjective audit? Also what is included in the term "analysis capabilities" and how will these items be sufficiently quantified to allow for a consistent audit approach across the various Regional Entities?

Response: Thank you for your comment.
1. See response to SRC.
2. The SDT has reviewed all proposed TOP and IRO standards from Project 2014-03, including TOP-001-3, and established the project scope accordingly as described in the SAR Justification White Paper.
3. Specific concerns related to the requirements will be addressed by the SDT in standards development. Analysis capabilities are described by the defined term Real-time Assessment.

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment: ERCOT supports the SRC's comments regarding the proposed SAR, but - should the SAR proceed - would urge the SDT to ensure that the focus remains on what needs to be done - not how it should be done.

Response: Thank you for your comment. See response to SRC.

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer: Yes

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Answer Comment: The SAR has the "NEW" Standard box checked but not the "Revision to existing Standard" box. Based on the statement below from the SAR, FirstEnergy feels the "Revision to existing Standard" should be checked also so other Standards can be included if necessary..

- P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.*

Response: Thank you for your comment. The SDT agrees and has revised the SAR accordingly.

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: No

Answer Comment: How does NERC's Project 2009-02 differ from the work about to begin in the NERC Synchrophasor Measurements Subcommittee (SMS)? Should this project be part of SMS? In my mind ther is a great deal of overlap between the new SMS and Project 2009-02 and to a large extent, Project 2009-2 is dependent on the work to be done by SMS. Entergy recommend a delay or no vote on this project until SMS work is completed.

Response: Thank you for your comment. The scope for Project 2009-02 addresses specific recommendations and directives as described in the SAR. This scope differs from the approved project scope for SMS. The SDT does not agree that Project 2009-02 is dependent upon completion of work done by SMS.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2009-02

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: Suggest revising the Purpose to make it more encompassing. Suggest the following wording:

To establish situational awareness capabilities with results-based requirements for monitoring and analysis used by System Operators in support of reliable Real-time System operations.

The concepts being proposed in the scope of the SAR can be realized by revising the appropriate TOP and IRO standards by either revising existing requirements, or adding requirements. A new standard may not be necessary. Therefore, the SAR should provide the Drafting Team with the flexibility to add requirements to IRO-010-2 and TOP-003. For example, Requirement R2 in IRO-010-2 stipulates that:

“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.”

This requirement satisfies both the posted Purpose of the SAR:

“To establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations,”
and our suggested revision above.

Response: Thank you for your comment. The SDT agrees that the reliability objectives proposed in the SAR could be accomplished by modifying approved or proposed standards and has modified the SAR accordingly. The SDT believes the SAR Purpose section encompasses the project objectives as written. The recommendation for the purpose section will be considered as standard requirements are developed.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Selected Answer: Yes

Answer Comment: We agree with the overall scope of the SAR. However, we do have a two concerns to address.

First, the SAR indicates that it will address all recommendations of the RTBPTF while the SAR Justification indicates that not all recommendations will be implemented. If by "addressing the recommendations" the SAR indicates that recommendation will considered based on its merits, we agree. Furthermore, we agree with the disposition of the vast majority of the recommendations as written in the SAR justification.

Second, if a "common understanding of *monitoring*" means a definition will be developed, we caution the drafting team to conduct a complete wholesale review of all NERC reliability standards to be sure the definition would not change the meaning of other requirements or cause confusion on applicability of the definition.

Response: Thank you for your comment. The project will address those recommendations listed in Table 1 of the SAR Justification White Paper. The SDT acknowledges the potential impact that a definition can have on the body of standards.

Oshani Pathirane - Hydro One Networks, Inc. - 1,3 - NPCC

Selected Answer: Yes

Answer Comment:

Hydro One Networks Inc. would like to provide the following additional recommendations for the SDT's consideration:

1. The effort required to capture activities/best practices the majority of entities have already employed may be of value;

2. The standard does not appear to deliver the intended future direction for system monitoring and ways to achieve this;

3. By the nature and competitiveness of the MS industry, providers will continue to develop and offer new functionalities that may or may not be desirable for every entity. The effort would be better suited to standardize requirements and allow for the industry to catch up to a common standard. In other words, this effort would provide minimal benefit for entities that already have a modern EMS and for others a large change to meet current requirements;

4. The goal should be to level-off the playing field and have all entities reach the same level of monitoring first.

Response: Thank you for your comments. The SDT believes these comments will be addressed through standards development.

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
John Allen	City Utilities of Springfield	SPP	1,4
Jason Smith	Southwest Power Pool Inc	SPP	2
Kevin Giles	Westar Energy,Inc.	SPP	1,3,5,6
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5

Mike Kidwell	Empire District Electric Company	SPP	1,3,5
Jess Gray	Omaha Public Power District	MRO	3
James "Jim" Nail	City of Independence, Missouri	SPP	3,5
Sing Tay	Oklahoma Gas and Elecric, Inc	SPP	1,3,5,6
Scott Williams	City Utilities of Springfield	SPP	1,4

Selected Answer: No

Answer Comment: Our review team believes that the standards process has resulted in a mature set of Reliability Standards that already fully address FERC Order 693. With that being said, we feel that there is no need for continuing efforts on this project for the fear of redundancy. We have concerns that the scope of the SAR could result in requirements that are redundant to other existing Standards and inappropriately set minimum capabilities based on a list of best practices. The SAR scope seems to focus on quality of information for entities in carrying out their adherence to other Standards. Additionally, we feel that perhaps the documentation of the entities capabilities should be captured in either the Rules of Procedure or other certification or registration procedures rather than in a Reliability Standard. Another option would be to include descriptions or clarification of those capabilities within the supporting documentation of the other Standards.

Response: Thank you for your comments. The SAR addresses concerns with redundancy by mapping recommendations to specific requirements in the SAR Justification White Paper. The SDT believes the project's reliability objectives, which were derived from BES event reports, Order No. 693 directives, and the RTBPTF report, should be achieved through development of appropriate results-based requirements. The SDT agrees that these capabilities should be demonstrated at the organization certification stage, and should also be maintained on an ongoing basis through adherence to standards. Development of standards is also appropriate since, in general, organization certifications are based on the body of approved standards.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment: 1. Texas RE noticed communicating results was not part of the SAR. Effective communications is part of situational awareness and can directly be related to the quality of information being provided as well as awareness of key monitoring and analysis capabilities. Monitoring and analysis capabilities should include communicating results to all entities requiring information. Is the SDT considering this type of communication? Texas RE is concerned the scope seems narrow. Has the SDT or NERC clearly identified all the recommendations and FERC directives have been thoroughly covered by the changes in all the relative Standards?

2. Texas RE acknowledges that FERC Order No. 693 mentioned that it did not wish to identify specific tools, but rather minimum capabilities. There are, however, standard industry tools for monitoring. Texas RE recommends the SDT consider making certain tools mandatory. Tools determine the status of reliability of the system. It seems as if the industry sees the need to call specific types of tools out but does not want the compliance aspects associated with the tools. State estimator and contingency analysis tool are extremely common utility practices to help ensure reliability. Is there a part of the BES that is not being monitored by a State Estimator or Contingency Analysis tool?

Response: Thank you for your comment.
1. The SDT will consider communication of quality and availability information in Project 2009-02. The scope of Project 2009-02 was developed through a comprehensive review as described in the SAR Justification White Paper.
2. Requirements developed for Project 2009-02 will not prescribe specific tools, consistent with NERC guidelines to develop Reliability Standards that are technology-neutral. Requirements are designed to specify performance outcomes and provide entities with flexibility for determining how to meet the reliability objectives.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:	In general, BPA agrees with the scope of the SAR, and conceptually with the effort to tie performance based metrics to real time situational awareness. BPA also agrees with the SAR DT, that the scope of the Project 2009-02 should avoid prescriptive assumptions regarding the implementation of real time tools by a specific entity. As noted in the SAR Justification, real time situational awareness is closely associated with the pending definition of Real-time Assessment. BPA suggests that the concept of providing operators with notification of Availability, as described by the SAR DT, is already implied by the pending requirements in proposed TOP-001-3 R13 and IRO-008-2 R4. *TOP-001-3 R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.* *IRO-008-2 R4: Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.* The process an entity develops to avoid a violation of these requirements will necessitate prompt notification any time the entity's ability to perform the Real Time Assessment is degraded. Additional requirements would therefore be either redundant or unnecessarily prescriptive. BPA notes that a measurement of the **quality** of monitoring or analysis tools is likely to be closely dependent on the tools and processes implemented by the individual entity. However, BPA agrees with the SAR DT that ongoing assessment of the tools and processes implemented by an entity to perform Real-time Assessment is both necessary and a gap in the existing standards. It is important to avoid the pitfall of implicitly requiring a specific implementation for Real Time Assessment. Any new standards developed by Project 2009-02 must also allow the industry to continue developing and improving on the best practices described by the NERC Real Time Best Practice Task Force in 2008.

Therefore, BPA suggests that Project 2009-02 should only focus on developing requirements for entities to establish, based on their own local implementation, 1) procedures for evaluating the quality of their Real Time Assessment and the information needed to perform it, and 2) the processes for maintaining the quality of the required information to the performance thresholds the entity determines are necessary for performing the Real Time Assessment.

Response: Thank you for your comment. The SDT agrees that availability notification of Real-time Assessment capabilities is addressed in proposed TOP and IRO standards. The SAR has been modified accordingly.

2. Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.

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 wishes to point out that our industry has recently approved TOP-001-3 and it is currently pending approval from FERC. Specifically, R8, R10, R10.1, R10.2, R11, R12, R13, and R19 addresses several blackout recommendations concerning knowing how your system is performing and how to communicate mitigating actions to others. Please take this into consideration when developing this Standard.

Response: Thank you for your comment.

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment: none

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Answer Comment:	Entergy has the following additional comments: 1. When writing standards for issues that are technology driven, extreme care must be used to avoid arbitrarly increasing costs without commensurare increase in benefit to reliability. 2. Standards should be technology neutral to the extent possible. 3. Need a bright-line voltage level guidance for which these new requirements apply. Different entities have their own definition of what consitutes Transmission levels. There presently exists a range from 100 kV to 44 kV in our region. 4. Need a bright-line guidance regarding extent of external monitoring that needs to be performed. A specific number, for example 10% impact, on internal lines and transformers would be extremely helpful. Currently entities in our region monitor anywhere from 5% to 10% impact, if possible, or up to three buses away.

Response: Thank you for your comments. The scope for this project includes quality and availability of monitoring and analysis capabilities. Determination of what should be monitored is not in scope, but is addressed by the applicable entities in other reliability standards.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Answer Comment:	Xcel Energy has questions about any new standards or proposed revisions to existing standards that would result from this project. How stringent are the requirements going to be? Will fully redundant systems be required? Can a TOP rely on the RC or other entity as a temporary backup? What about if the RC goes down? Additionally, we have concerns about the level of detail that would be required. We believe that a requirment to analyze contingencies on neighboring systems could cause undue burden on smaller systems with larger neighbors.

Response: Thank you for your comment. Specific questions about requirements are not within scope of the SAR but will be addressed in standards development.

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2009-02

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:

Any revisions made must not address the specifics of what the situational awareness capabilities are, but must focus on the adequacy of the monitoring and analysis.

This proposed project should be considered for a guideline document as opposed to a standard. As written, the SAR appears to intend to write a "how" not "what" standard (i.e. it does appear to be a results-based standard). We believe that the existing Standards (i.e. IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (i.e. without defining the "how"), which is appropriate.

As an alternative, this could be considered a process to be used for certifying new entities for assurance that they have the ability to monitor appropriately in accordance with the Standard's Requirements.

To avoid these issues in the future and to support communicating to FERC that a standard is not needed but another tool is more suitable, we suggest the future SARs be voted on by industry as to whether to proceed as a Standards project or use another means to achieve the ends.

Response: Thank you for your comment. The SDT believes that the recommendations from BES event reports and the RTBPTF Report that are referenced in the project SAR establish the need for development of reliability standards. Project 2009-02 has been scoped to include recommendations that have not been addressed in other standards. The SDT agrees that these capabilities should be demonstrated at the organization certification stage, and should also be maintained on an ongoing basis through adherence to standards. Development of standards is also appropriate since, in general, organization certifications are based on the body of approved standards.

Kathleen Black - DTE Energy - 3,4,5 - RFC

Answer Comment: 2009-02 Real-time monitoring and analysis capabilities-S15 (Page 18 & 19), S18 (Page 21 and 22) and S33 (Page 26) all list EOP-011-1. EOP-011-1 is not effective due to not being approved by FERC. Although EOP-011-1 was written to consolidate EOP-001-2.1b, EOP-002-3.1 and EOP-003-2, we question if this project should be listing EOP-011-1 rather than the other 3 standards which are effective and approved.

Response: Thank you for your comment. The SAR DT included board-adopted Reliability Standards in its review where appropriate. The SDT does not consider this to be premature at this stage.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Answer Comment: There are two minor issues in the SAR Justification. On page 11, the last paragraph refers to Table 1. Yet, there is no Table 1. We assume Table 2 is supposed to be Table 1.

On page 15 regarding recommendation S3, “Addresses” should be “Addressed.”

Response: Thank you for your comment. The sentence on page 11 refers to Table 1: Report Recommendations to Address in Project 2009-02, which is found on page 9. The correction has been made to recommendation S3 on page 15.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment: Texas RE agrees with the RTBPTF report which states “Develop a new weather data requirement related to situational awareness and real-time operational capabilities.” The drafting team’s response, “EOP-010-1 covers space weather dissemination. The SAR DT views monitoring other weather information as common utility practice that does not require a reliability standard”, is concerning because registered entities might not monitor weather as they should. Weather is extremely pertinent to situational awareness and real-time operational capabilities. Weather has a significant impact and, too often, exacerbates reliability issues. If it is a common utility practice than successful compliance should not be an issue. Is the SDT considering a Guideline like what was done for the common utility practice of preparing a generator for winter operation?

Response: Thank you for your comment. The SDT agrees that weather information is important for situational awareness and Real-time operational capabilities. However, there was general agreement within the SDT and participants at the SAR development technical conference held in June 2015 that, since the time of the RTBPTF report, weather data usage by operators has become common practice and as a result a standard requirement would not provide reliability benefit. Development of a guideline for weather information is not in scope for this project.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment: N/A

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

This draft is the first posting of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	July 16 - August 17, 2015

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2015
45-day formal comment period with additional ballot	December 2015
10-day final ballot	January 2016
NERC Board (Board) adoption	February 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:** **Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **IRO-018-1**
3. **Purpose:** **Establish requirements for Real-time monitoring and analysis capabilities used by Reliability Coordinator System Operators in support of reliable System operations.**
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirement R1: The Reliability Coordinator (RC) uses a set of Real-time data identified in approved standard IRO-010-1a Requirement R1 and proposed standard IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform monitoring and Real-time Assessments appear in other standards.

Requirement R1 Part 1.2 of this standard specifies the RC shall include actions to coordinate resolution of data quality discrepancies in its Operating Process or Operating Procedure. These actions could be the same as the process to resolve data conflicts required by IRO-010-2 Requirement R3 Part 3.2, provided that this process could resolve Real-time data quality issues.

R1. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

1.1. Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to:

1.1.1. Data outside of a prescribed data range;

1.1.2. Analog data not updated within a predetermined time period;

1.1.3. Data entered manually to override telemetered information; and

1.1.4. Data otherwise identified as invalid or suspect.

1.2. Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data.

M1. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Procedure or Operating Process in electronic or hard copy format meeting all provisions of Requirement R1, and 2) evidence the Reliability Coordinator implemented the Operating Procedure or Operating Process as called for in the Operating Procedure or Operating Process, such as dated operator or supporting logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R2. Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M2. Each Reliability Coordinator shall have evidence it provided its System Operators with indications of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to, computer printouts, system specifications, or other evidence.

Rationale for Requirements R3 and R4: Requirements R3 and R4 ensure the RC's System Operators have procedures and receive indication(s) to address issues related to the quality of the analysis inputs used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards.

R3. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

3.1. Criteria for evaluating the quality of any analysis used in its Real-time Assessments; and

3.2. Actions to resolve quality deficiencies in any analysis used in its Real-time Assessments.

M3. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Procedure or Operating Process in electronic or hard copy format meeting all provisions of Requirement R3, and 2) evidence the Reliability Coordinator implemented the Operating Procedure or Operating Process as called for in the

Operating Procedure or Operating Process, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R4. Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Reliability Coordinator shall have evidence it provided its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

Rationale for Requirement R5: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An independent alarm process monitor is one that would not fail with a simultaneous failure of the alarm processor. A 'heartbeat' or 'watchdog' monitoring system may accomplish this objective.

R5. Each Reliability Coordinator shall utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall have evidence it utilized an independent alarm process monitor that provided notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 it was compliant for the full-time period since the last audit.

The Reliability Coordinator 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 Reliability Coordinator shall retain evidence of compliance for Requirements R1, R2, and R5 and Measures M1, M2, and M5 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall retain evidence of compliance for Requirements R3 and R4 and Measures M3 and M4 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator 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 Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes 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 Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 and Part 1.2.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 and Part 1.2; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	N/A	N/A	The Reliability Coordinator did not provide its System Operators with indication(s) of the quality of Real-time

				data used to perform its Real-time monitoring and Real-time Assessments.
R3.	N/A	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 and Part 3.2.	The Reliability Coordinator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 and Part 3.2; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments.
R4.	N/A	N/A	N/A	The Reliability Coordinator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.
R5.	N/A	N/A	N/A	The Reliability Coordinator did not utilize an independent alarm process

				monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by existing and proposed TOP and IRO standards. As used in TOP and IRO standards, monitoring involves observing operating status and operating value(s) in Real-time for awareness of system conditions. Real-time monitoring includes the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

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.

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

This draft is the first posting of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	July 16 - August 17, 2015

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2015
45-day formal comment period with additional ballot	December 2015
10-day final ballot	January 2016
NERC Board (Board) adoption	February 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:** **Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **TOP-010-1**
3. **Purpose:** **Establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations.**
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Operators
     - **4.1.2.** Balancing Authorities
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirement R1: The Transmission Operator (TOP) uses a set of Real-time data identified in proposed standard TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform monitoring and Real-time Assessments appear in other standards.

Requirement R1 Part 1.2 of this standard specifies the TOP shall include actions to coordinate resolution of Real-time data quality discrepancies in its Operating Process or Operating Procedure. These actions could be the same as the process to resolve data conflicts required by proposed TOP-003-3 Requirement R5 Part 5.2 provided that this process could resolve Real-time data quality issues.

R1. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

1.1. Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to:

1.1.1. Data outside of a prescribed data range;

1.1.2. Analog data not updated within a predetermined time period;

1.1.3. Data entered manually to override telemetered information; and

1.1.4. Data otherwise identified as invalid or suspect.

1.2. Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data.

M1. Each Transmission Operator shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time Monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Procedure or Operating Process in electronic or hard copy format meeting all provisions of Requirement R1, and 2) evidence the Transmission Operator implemented the Operating Procedure or Operating Process as called for in the Operating Procedure or Operating Process, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R2: The Balancing Authority (BA) uses a set of Real-time data identified in proposed standard TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other standards.

Requirement R2 Part 2.2 of this standard specifies the BA shall include actions to coordinate resolution of Real-time data quality discrepancies in its Operating Process or Operating Procedure. These actions could be the same as the process to resolve data conflicts required by proposed TOP-003-3 Requirement R5 Part 5.2 provided that this process could resolve Real-time data quality issues.

R2. Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

2.1. Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to:

2.1.1. Data outside of a prescribed data range;

2.1.2. Analog data not updated within a predetermined time period;

2.1.3. Data entered manually to override telemetered information; and

2.1.4. Data otherwise identified as invalid or suspect.

2.2. Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data.

M2. Each Balancing Authority shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to: 1) an Operating Procedure or Operating Process in electronic or hard copy format meeting all provisions of Requirement R2, and 2) evidence the Balancing Authority implemented the Operating Procedure or Operating Process as called for in the Operating Procedure or Operating Process, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R3. Each Transmission Operator shall provide its System Operators with indication(s) of the quality of Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Transmission Operator shall have evidence it provided its System Operators with indications of the quality of Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to, computer printouts, system specifications, or other evidence.

R4. Each Balancing Authority shall provide its System Operators with indication(s) of the quality of Real-time data necessary to perform its analysis functions and Real-time monitoring. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Balancing Authority shall have evidence it provided its System Operators with indications of the quality of Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to, computer printouts, system specifications, or other evidence.

Rationale for Requirements R5 and R6: Requirements R5 and R6 ensure the TOP's System Operators have procedures and receive indication(s) to address issues related to the quality of the analysis inputs used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards.

R5. Each Transmission Operator shall implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

5.1. Criteria for evaluating the quality of any analysis used in its Real-time Assessments; and

5.2. Actions to resolve quality deficiencies in any analysis used in its Real-time Assessments.

M5. Each Transmission Operator shall have evidence it implemented its Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Procedure or Operating Process in electronic or hard copy format meeting all provisions of Requirement R5, and 2) evidence the Transmission Operator implemented the Operating Procedure or Operating Process as called for in the

Operating Procedure or Operating Process, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R6. Each Transmission Operator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M6. Each Transmission Operator shall have evidence it provided its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessment capabilities. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

Rationale for Requirement R7: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An independent alarm process monitor is one that would not fail with a simultaneous failure of the alarm processor. A 'heartbeat' or 'watchdog' monitoring system may accomplish this objective.

R7. Each Transmission Operator and Balancing Authority shall utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

M7. Each Transmission Operator and Balancing Authority shall have evidence it utilized an independent alarm process monitor that provided notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 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 applicable entity shall retain evidence of compliance for Requirements R1 through R4, and Requirement R7, and Measures M1 through M4, and Measure M7, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall retain evidence of compliance for Requirements R5 and R6 and Measures M5 and M6 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity 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.

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 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 Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 and Part 1.2.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 and Part 1.2; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the

			Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 and Part 2.2.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 and Part 2.2; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.
R3.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its Real-time monitoring and Real-time Assessments.
R4.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its

				analysis functions and Real-time monitoring.
R5.	N/A	N/A	The Transmission Operator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include one of the elements listed in Part 5.1 and Part 5.2.	The Transmission Operator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include any of the elements listed in Part 5.1 and Part 5.2; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments.
R6.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.
R7.	N/A	N/A	N/A	The responsible entity did not utilize an independent alarm process monitor that provides notification(s) to its

				System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by existing and proposed TOP and IRO standards. As used in TOP and IRO standards, monitoring involves observing operating status and operating value(s) in Real-time for awareness of system conditions. Real-time monitoring includes the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

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.

Implementation Plan

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Requested Approvals

- IRO-018-1 - Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
- TOP-010-1 - Real-time Reliability Monitoring and Analysis Capabilities

Requested Retirements

- None

Prerequisite Approval

- TOP-003-3 Operational Reliability Data

Proposed TOP-010-1 contains requirements addressing the quality of data necessary for Transmission Operators and Balancing Authorities to perform Real-time monitoring and analysis functions. Requirements for specifying and providing this data appear in TOP-003-3. Accordingly, proposed TOP-010-1 cannot become effective prior to TOP-003-3.

Revisions to Defined Terms in the NERC Glossary

None

Applicable Entities

- Reliability Coordinators
- Transmission Operators
- Balancing Authorities

Effective Date

IRO-018-1

- Requirements R1, R2, and R5 shall become effective on the first day of the first calendar quarter that is 12 months after the date that this 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, Requirements R1, R2, and R5 shall become effective on the first day of the first calendar quarter that is 12 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
- Requirements R3 and R4 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, Requirements R3 and R4 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

TOP-010-1

If the prerequisite approval occurs on or before approval of the standards in Project 2009-02:

- Requirements R1, R2, R3, R4, and R7 shall become effective on the first day of the first calendar quarter that is 12 months after the date that this 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, Requirements R1, R2, R3, R4, and R7 shall become effective on the first day of the first calendar quarter that is 12 months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
- Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

If the prerequisite approval occurs after approval of the standards in Project 2009-02:

- Requirements R1, R2, R3, R4, and R7 shall become effective on the first day of the first calendar quarter that is 12 months after the date that TOP-003-3 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, Requirements R1, R2, R3, R4, and R7 shall become effective on the first day of the first calendar quarter that is 12 months after the date TOP-010-1 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
- Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date that TOP-003-3 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, Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date TOP-010-1 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Unofficial Comment Form

Project 2009-02 Real-time Monitoring and Analysis Capabilities

IRO-018-1 and TOP-010-1

DO NOT use this form for submitting comments. Use the electronic form to submit comments on IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities and TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities. The electronic comment form must be completed by **8 p.m. Eastern, Monday, November 9, 2015**.

Documents and information about this project are available on the project page. If you have any questions, contact Standards Developer, Mark Olson (via email), or at (404) 446-9760.

Background Information

Project 2009-02 Real-time Monitoring and Analysis Capabilities originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). The project SAR was revised earlier this year to account for proposed revisions to TOP and IRO standards developed in Project 2014-03 that are pending regulatory approval. Project 2009-02 is developing requirements to address monitoring and analysis capability issues identified in the 2008 RTBPTF report and the 2011 Southwest Outage Report, as well as addressing FERC Order No. 693 directives.

The Standard Drafting Team (SDT) developed two proposed Reliability Standards to meet the objectives outlined in the project SAR. IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities addresses issues related to the quality and availability of Reliability Coordinator (RC) monitoring and analysis capabilities. TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities contains similar proposed requirements for Transmission Operators (TOPs) and Balancing Authorities (BAs).

Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. The SDT has proposed a new standard IRO-018-1 to address RC monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

☐ Yes
☐ No
Comments:

2. The SDT has proposed a new standard TOP-010-1 to address TOP and BA monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

☐ Yes
☐ No
Comments:

3. Do you agree with the Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

☐ Yes
☐ No
Comments:

4. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

☐ Yes
☐ No
Comments:

5. Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.
Comments:

Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	Project 2009-02: Real-time Reliability Monitoring and Analysis Capabilities		
Date Submitted:	June 18, 2015		
SAR Requester Information			
Name:	Saad Malik		
Organization:	Peak Reliability		
Telephone:	970.776.5635	E-mail:	smalik@peakrc.com
SAR Type (Check as many as applicable)			
☒ New Standard ☒ Revision to existing Standard		☐ Withdrawal of existing Standard ☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
To establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations.
Industry Need (What is the industry problem this request is trying to solve?):
According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* dated April 2004 (2003 Blackout Report), a principal cause of the August 14 blackout was a lack of situational awareness. Recommendation 22 of the 2003 Blackout Report states that the industry should "evaluate and adopt better Real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate Real-time tools and their usage within the industry. The Task Force produced the report *Real-Time Tools Survey Analysis and Recommendations* dated March 13, 2008 (RTBPTF Report)

SAR Information
that included recommendations for the functionality, performance, and management of Real-time tools. The FERC and NERC Staff Report *Arizona-Southern California Outages on September 8, 2011* (2011 Southwest Outage Report) also cited weaknesses in Real-time situational awareness and recommended improvements in Real-time monitoring and analysis capabilities. In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to System operators: • P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.* • P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.* • P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.* This SAR addresses the event reports, Order No. 693 directives, and recommendations from the RTBPTF Report that have not been addressed in other standards projects. The SAR Drafting Team also conducted a Technical Conference on June 4, 2015 to obtain stakeholder input on reliability objectives to be addressed in the proposed project.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Standards Drafting Team (SDT) shall develop requirements and definition(s), as needed, for Real-time monitoring and analysis capabilities to ensure effective operator situational awareness. The project will address recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Situational awareness of Real-time system operations is enabled through monitoring and analysis tasks performed by operators. Existing and proposed TOP and IRO standards and definitions developed in

SAR Information
Project 2014-03 Revisions to TOP and IRO Standards require Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed project will provide additional reliability benefits by addressing issues with the availability and information quality of Real-time monitoring and analysis capabilities. Specifically, the SDT will develop requirements and definition(s), as needed, to accomplish the following: • Establish a common understanding of *monitoring* as it applies to Real-time situational awareness of the Bulk Electric System (BES), • Provide operators with indication(s) of the quality of information being provided by *monitoring* capabilities and procedure(s) to address data quality issues, • Provide operators with notification(s) during unplanned loss of *monitoring* capabilities, and • Provide operators with indication(s) of the quality of information being provided by *analysis* capabilities and procedure(s) to address analysis quality issues. When completed, the project will have addressed recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	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 a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.

Reliability Functions		
☐	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 service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	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.
☒	2. The frequency and voltage of interconnected bulk power 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 power 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 power systems shall be developed, coordinated, maintained and implemented.

Reliability and Market Interface Principles	
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power 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 of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability 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**
Project 2014-03 Revisions to TOP and IRO Standards	Proposed TOP and IRO standards and definitions from Project 2014-03 require RC, TOP, and BAs to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed standards and definitions are pending regulatory approval.

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	Project 2009-02: Real-time Reliability Monitoring and Analysis Capabilities		
Date Submitted:	June 18, 2015		
SAR Requester Information			
Name:	Saad Malik		
Organization:	Peak Reliability		
Telephone:	970.776.5635	E-mail:	smalik@peakrc.com
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
To establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations.
Industry Need (What is the industry problem this request is trying to solve?):
According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* dated April 2004 (2003 Blackout Report), a principal cause of the August 14 blackout was a lack of situational awareness. Recommendation 22 of the 2003 Blackout Report states that the industry should "evaluate and adopt better Real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate Real-time tools and their usage within the industry. The Task Force produced the report *Real-Time Tools Survey Analysis and Recommendations* dated March 13, 2008 (RTBPTF Report)

SAR Information
that included recommendations for the functionality, performance, and management of Real-time tools. The FERC and NERC Staff Report *Arizona-Southern California Outages on September 8, 2011* (2011 Southwest Outage Report) also cited weaknesses in Real-time situational awareness and recommended improvements in Real-time monitoring and analysis capabilities. In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to System operators: • P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.* • P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.* • P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.* This SAR addresses the event reports, Order No. 693 directives, and recommendations from the RTBPTF Report that have not been addressed in other standards projects. The SAR Drafting Team also conducted a Technical Conference on June 4, 2015 to obtain stakeholder input on reliability objectives to be addressed in the proposed project.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Standards Drafting Team (SDT) shall develop requirements and definition(s), as needed, for Real-time monitoring and analysis capabilities to ensure effective operator situational awareness. The project will address recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Situational awareness of Real-time system operations is enabled through monitoring and analysis tasks performed by operators. Existing and proposed TOP and IRO standards and definitions developed in

SAR Information
Project 2014-03 Revisions to TOP and IRO Standards require Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed project will provide additional reliability benefits by addressing issues with the availability and information quality of Real-time monitoring and analysis capabilities. Specifically, the SDT will develop requirements and definition(s), as needed, to accomplish the following: • Establish a common understanding of *monitoring* as it applies to Real-time situational awareness of the Bulk Electric System (BES), • Provide operators with indication(s) of the quality of information being provided by *monitoring* capabilities and procedure(s) to address data quality issues, • Provide operators with notification(s) during unplanned loss of *monitoring* capabilities, • Provide operators with indication(s) of the quality of information being provided by *analysis*, and capabilities and procedure(s) to address analysis quality issues.~~, and~~ • ~~Provide operators with notification(s) during unplanned loss of *analysis* capabilities.~~ When completed, the project will have addressed recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	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 a Balancing Authority Area and supports Interconnection frequency in real time.

Reliability Functions		
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	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 service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	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.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.

Reliability and Market Interface Principles	
☒	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.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power 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 power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power 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 of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability 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
Project 2014-03 Revisions to TOP and IRO Standards	Proposed TOP and IRO standards and definitions from Project 2014-03 require RC, TOP, and BAs to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed standards and definitions are pending regulatory approval.

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

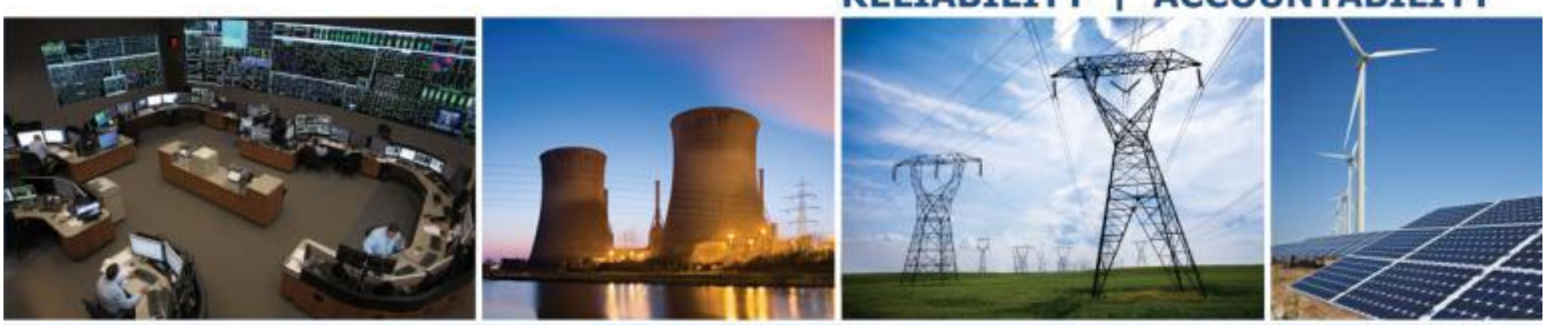
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Justification

Project 2009-02 Real-time Monitoring and Analysis Capabilities

RELIABILITY | ACCOUNTABILITY



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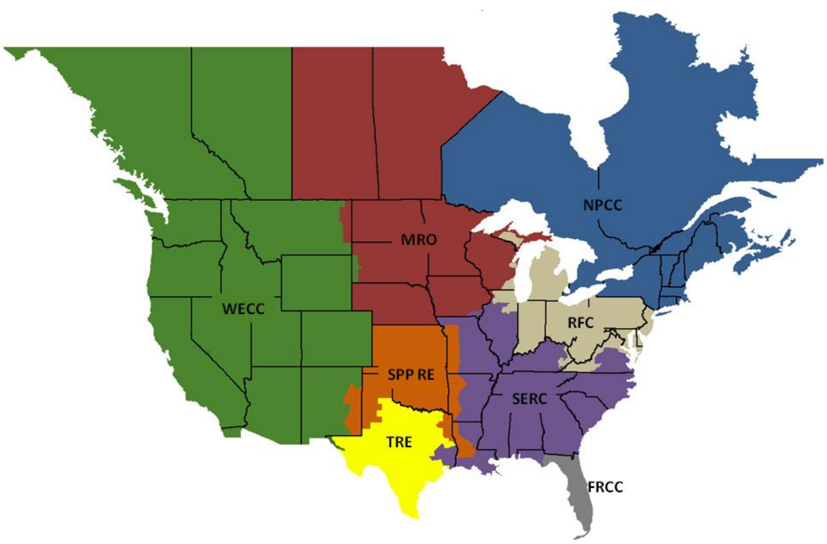
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

In April 2015, the Standards Committee appointed a new Standards Authorization Request (SAR) Drafting Team (SAR DT) for Project 2009-02 Real-time Monitoring and Analysis Capabilities. This project originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). Several new Reliability Standards and defined terms have been approved or filed for approval in the years since Project 2009-02 was initiated, including the standards developed in Project 2014-03 Revisions to TOP and IRO Standards. As a result, many of the original issues identified by the RTBPTF for Project 2009-02 have been addressed. In addition, relevant observations and recommendations have emerged from more recent events on the Bulk Electric System (BES) and operating practices have evolved over time. The SAR DT has reviewed previous work done in Project 2009-02, new standards and defined terms, relevant industry report findings and recommendations including those contained in the 2011 Southwest Outage report, and industry observations and practices relevant to real-time situational awareness to assist in developing a comprehensive SAR.

This white paper describes the SAR DT's approach to developing the SAR and discusses the technical basis for developing Reliability Standards in Project 2009-02. This white paper and the associated SAR together are intended to fully describe the project purpose, industry need, and project scope.

Chapter 1 – Background

FERC Order No. 693[1] highlights the need for a minimum set of capabilities to be available to assist operators in making real-time decisions. The work done by the RTBPTF, which was formed by NERC in response to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, became the basis for the Real-time Monitoring and Analysis Capabilities (RTMAC) standards development project when it was initiated in 2009. Although Reliability Standards affecting the operating reliability of the Bulk Electric System (BES) have improved significantly over the years since first becoming mandatory in 2007, a reliability issue has persisted in the area of real-time situational awareness capabilities as highlighted in BES event reports and an independent review of the NERC Reliability Standards. A review of industry reports and recommendations pertaining to real-time monitoring and analysis capabilities is provided in this document and in the Appendix. These recommendations, along with the FERC Order No. 693 directives, describe the industry need for the current RTMAC standards project.

BES Event Reports

Project 2009-02, like some other Reliability Standards projects, is informed by the lessons learned from past outages. The two significant outages discussed below highlight issues in real-time situational awareness, among other reliability concerns. Many Communications (COM), Transmission Operations (TOP), and Interconnection Reliability Operations (IRO) standards have addressed event report recommendations to improve the way the BES is planned and operated. The scope of Project 2009-02 is intended to include remaining recommendations from the 2003 Blackout Report and the 2011 Southwest Outage Report that pertain to real-time monitoring and analysis capabilities.

2003 Blackout Report

The largest blackout in history to affect North America began on the afternoon of August 14, 2003 and disrupted over 61,800 Megawatts of electric load in the Northeastern U.S. and the Canadian province of Ontario. Severe impacts to electrical service lasted for nearly one week and an estimated 50 million people were affected. A comprehensive investigation conducted by U.S. and Canadian government and industry leaders identified a host of principal and contributing causes, including:

- Failure to maintain adequate reactive power support,
- Failure to ensure operation within secure limits,
- Inadequate vegetation management,
- Inadequate operator training,
- Failure to identify emergency conditions and communicate that status to neighboring systems, and
- Inadequate regional-scale visibility over the Bulk-Power System (BPS).

Among other causes, the 2003 blackout was linked to dysfunction of SCADA/EMS systems. Additionally, investigators pointed out that several deficiencies leading to the 2003 blackout were also identified weaknesses in previous outages, indicating the need for more effective response. Previous post-event reports included recommendations aimed at improving capabilities for visualizing changes to facilities within the system, and for visualizing changes to facilities in neighboring systems that could have a potential impact. A recurring recommendation also focused on providing capabilities for operators to evaluate courses of action. These

[1] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, 72 Fed. Reg. 16416 at P 1660 (Apr. 4, 2007), FERC Stats. And Regs.¶ 31,242, *order on reh'g,* Order No. 693-A, 120 FERC ¶ 61,053 (2007) (Order No. 693).

observations led to the recommendation in the final report of the 2003 blackout for NERC to **evaluate and adopt better real-time tools for operators and reliability coordinators.**[2]

In response, the NERC Operating Committee organized the RTBPTF to study the real-time situational awareness practices in use within the electric power industry and make recommendations concerning the establishment of minimum capabilities necessary for reliable operations. The RTBPTF report *Real-time Tools Survey Analysis and Recommendations,*[3] completed in 2008, is the result of extensive information gathering and analysis and includes recommendations for new or enhanced Reliability Standards, operating guides, and areas for further analysis. This report became a basis for initiating the Real-time Monitoring and Analysis Capabilities project in 2009.

Although exhaustive and comprehensive, some of the RTBPTF recommendations go beyond the scope of situational awareness monitoring and capabilities. In addition, many other recommendations have been addressed in other subsequent standards projects. The appendix provides a description of RTBPTF report recommendations and the SAR DT's determination of applicability within the scope of Project 2009-02.

An early Concept White Paper describing potential performance, availability, quality, and maintenance parameters based on the RTBPTF Report was developed in 2011. The SAR DT reviewed the white paper and confirmed that, due to significant changes to Reliability Standards and operating practices since it was drafted, the 2011 Concept White Paper is no longer relevant to the current effort in Project 2009-02.

2011 Southwest Outage Report

Like the 2003 blackout in the northeast, the blackout that occurred in the southwest in September 2011 was partly due to, or exacerbated by, inadequate real-time situational awareness. On the afternoon of September 8, 2011, the loss of a single 500 kV line led to widespread cascading outages affecting 2.7 million customers in Arizona, Southern California, and Baja, Mexico. Inadequate operations planning was a significant factor in the failure to maintain a secure N-1 state. However, the report also highlighted several concerns with entities and their ability to monitor, identify, and plan for the next most critical contingency in real-time.[4]

Project 2014-03 - Revisions to TOP and IRO Standards addressed many of the recommendations contained in the 2011 Southwest Outage Report related to operations planning and real-time situational awareness. A complete description is provided in the Southwest Outage Report mapping document for Project 2014-03.[5] Revised definitions and performance requirements for Real-time Assessments and Operational Planning Analysis and proposed requirements for developing and implementing Operating Plans to prevent and mitigate operating limit exceedances address most of the real-time situational awareness recommendations from the report. However some recommendations contain aspects pertaining to real-time capabilities that should be considered in Project 2009-02, as described in the appendix. Accordingly, Project 2009-02 will develop requirements to address remaining recommendations as described in the following chapter.

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[2] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* Recommendation 22*,* available at http://www.nerc.com/pa/rrm/ea/2003%20Blackout%20Final%20Report/Forms/AllItems.aspx.

[3] *Real-Time Tools Survey Analysis and Recommendations* (March 13, 2008), available at http://www.nerc.com/comm/OC/Realtime%20Tools%20Best%20Practices%20Task%20Force%20RTBPTF%2020/Real-Time%20Tools%20Survey%20Analysis%20and%20Recommendations.pdf.

[4] *Arizona-Southern California Outages on September 8, 2011* (April 2012), available at http://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf.

[5] See the project page for 2014-03, available at http://www.nerc.com/pa/stand/pages/project-2014-03-revisions-to-top-and-iro-standards.aspx.

FERC Directives

In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to operators.[6] FERC indicated that the intent of the directive is to ensure operating entities have adequate tools to perform their real-time reliability functions.[7]

- P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.*
- P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.*
- P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.*

Independent Experts Review Project (IERP) Report

In 2013, NERC retained a team of five industry experts to assess the quality of the enforceable body of standards and make recommendations for improvements that could be implemented by NERC and the industry.[8] Among the recommendations made by the panel of experts was the identification of potential risks to reliability that may not be adequately addressed in Reliability Standards. The report recommended resuming development of the Real-time Monitoring and Analysis Capabilities standards project.

Proposed TOP and IRO Standards

Since Project 2009-02 was initiated in 2009, many standards and definitions have been revised or developed that address real-time situational awareness issues. In particular, the revised TOP and IRO standards in Project 2014-03, which are pending regulatory approval, include key provisions for real-time situational awareness and operations planning. In reviewing the RTBPTF report recommendations for applicability in the current Project 2009-02 effort, the SAR DT considered the Project 2014-03 standards as noted in the Appendix.

The proposed TOP and IRO standards in Project 2014-03 provide requirements for performing monitoring and analysis through the definition of Real-time Assessment, Operational Planning Analysis, and the relevant requirements. Accordingly, additional requirements to perform monitoring or analysis will not be included in the scope for Project 2009-02. Furthermore, requirements for data exchange to support real-time monitoring and analysis will not be included in scope for Project 2009-02 because they are addressed through data specification requirements in IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3.

[6] Order No. 693 at P 905 (approving IRO-002-1 and directing modifications) and P 1665 (approving TOP-006-1 and directing modifications.

[7] Additionally, in approving VAR-001-1 - Voltage and Reactive Control, the Commission directed NERC to develop modifications to the standard to require periodic performance of voltage stability analysis to assist in real-time operations. The commission clarified that this could be accomplished through online tools where available, or offline simulation tools.

- §1875: *...[w]e direct the ERO, through its Reliability Standards development process, ...to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.*

VAR-001 was revised in the Project 2013-04, however the revised standard did not include a requirement for periodic performance of voltage stability analysis because voltage stability analysis is performed per SOL Methodology developed under FAC standards.

[8] See The Standards Independent Experts Review Project report. Available at www.nerc.com /pa/Stand/_layouts/xlviewer.aspx?id=/pa/Stand/Documents/P81_and%20IERP_Recommendations_for_Retirement_010815.xlsx.

Technical Conference

NERC and the SAR DT held a Technical Conference in Atlanta on June 4, 2015, to obtain industry input on reliability issues to be addressed in the proposed project. Participant subject matter experts representing a diverse mix of regional and functional entities shared their perspectives on the use of real-time situational awareness capabilities for reliable operations. There was consensus that many RTBPTF recommendations have been addressed in current or proposed TOP and IRO standards. However, Technical Conference participants agreed that issues identified by the RTBPTF pertaining to availability and information quality of real-time monitoring and analysis capabilities were still relevant.

Chapter 2 – Project Scope

The SAR DT has reviewed all recommendations from the RTBPTF and relevant recommendations from event reports, along with the existing body of standards, to identify remaining issues that should be in the scope for Project 2009-02. Table 1 below shows the resulting recommendations to be addressed. Additionally, the project will address outstanding FERC directives discussed in the preceding chapter.

Table 1: Report Recommendations to Address in Project 2009-02

Source	Recommendation	Discussion	Applicable Entity
2003 Blackout Report	Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators.	Project 2009-02 will develop requirements for real-time reliability monitoring and analysis capabilities to address issues not already addressed in other Reliability Standards. RTBPTF report recommendations will be considered in development.	RC, TOP, BA
2011 Southwest Outage Report	Recommendation 12 - [entities] should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2009-02 will develop requirements to improve the adequacy and operation of real-time monitoring and analysis capabilities. Requirements addressing the frequency that real-time tools run are contained in other standards and are not in the scope of this project.	RC, TOP, BA
RTBPTF Report	S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • Alarm Tools • Telemetry Data Systems • Network Topology Processor • State Estimator • Contingency Analysis	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. Prescription of specific tools is not in scope. Project approach is discussed below.	RC, TOP, BA as discussed below
RTBPTF Report	S7 - S8, S11-S12, S40 - Availability of various monitoring and analysis capability processes	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring capabilities are not available (i.e., not performing their intended function).	RC, TOP, BA

Project Purpose and Approach

Project 2009-02 will develop requirements for real-time monitoring and analysis capabilities used by operators in support of reliable System operations. Functional requirements for performing *monitoring* and *analysis* tasks are well established in Reliability Standards as discussed throughout this white paper. However, reliability could be improved by:

- Developing a common understanding of *monitoring* as it applies to real-time situational awareness of the BES,
- Providing operators with indication(s) of the quality of information being provided by *monitoring* and *analysis* capabilities, and
- Providing operators with notification(s) during unplanned loss of *monitoring* capabilities.

Project 2009-02 will develop requirements and definition(s), as needed, to accomplish these reliability objectives as discussed.

Real-time Situational Awareness Concept

From the RTBPTF Report:

> *Situational awareness, as RTBPTF understands it, means ensuring that accurate information on current system conditions, including the likely effects of future contingencies, is continuously available in a form that allows operators to quickly grasp and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations.*

The Project 2009-02 SAR DT believes that situational awareness encompasses two broad capabilities: monitoring and analysis. To be effective in supporting real-time situational awareness, monitoring and analysis must:

- Be performed with sufficient frequency to allow operators to understand operating conditions and take corrective actions when necessary,
- Provide awareness of information quality to allow operators to assess the accuracy of information being received on system conditions and take corrective actions when necessary, and
- Indicate when monitoring or analysis processes are not operating normally or are unavailable in order to provide operator awareness of the accuracy of the information being provided.

Project 2009-02 will develop new requirements and definition(s), as needed, that support this concept of situational awareness without duplicating aspects that are already addressed in the existing and proposed body of Reliability Standards. As discussed in the preceding chapter, requirements for the Reliability Coordinator (RC), Transmission Operator (TOP), and Balancing Authority (BA) to perform monitoring and analysis are covered under existing and proposed TOP and IRO standards. Therefore, Project 2009-02 will focus on developing requirements to address information quality and operator awareness of real-time monitoring and analysis capabilities. Table 2 shows reliability objectives that should be addressed in requirements for this project.

Monitoring

Monitoring BES facilities in real-time is a primary function of the RCs, TOPs, and BAs and is addressed in existing and proposed TOP and IRO standards. For RCs, proposed IRO-002-4 states:

> *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.*

For TOPs and BAs, proposed TOP-001-3 states:

> *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.*

The SAR DT understands *monitoring* capabilities may include both alarming and information visualization. Project 2009-02 will aim to develop a consistent understanding of *monitoring* within the industry. The project will also address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of information being provided by a monitoring system, and indication when a monitoring system is not operating normally.

Analysis

The *analysis* component of the Real-time situational awareness concept is described by the definition of Real-time Assessment, which is pending FERC approval along with the proposed TOP and IRO standards. The proposed definition is as follows:

> ***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.)*

Requirements for performing Real-time Assessments are contained in proposed IRO-008-2 and TOP-001-3:

> ***Proposed IRO-008-2***
> *R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.*
>
> ***Proposed TOP-001-3***
> *R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.*

The SAR DT believes the proposed definition of Real-time Assessment and the requirements in proposed IRO-008-2 and TOP-001-3 provide RCs and TOPs with flexibility to determine which real-time tools, such as State Estimator, Contingency Analysis, and Stability Applications, are necessary to meet their real-time reliability functions. Consequently, prescriptive requirements for real-time tools are not in scope for Project 2009-02.

The project will address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of the analysis used in Real-time Assessments.

Table 2: Project 2009-02 Reliability Objectives

	Monitoring Capabilities	Analysis Capabilities
Quality	Provide operator with indication of information quality and procedures to address data quality issues.	Provide operator with indication of information quality and procedures to address analysis quality issues.
Availability	Provide operator with notification any time monitoring system is not operating normally.	N/A

Appendix – Report Recommendations

The table below contains recommendations for improved real-time situational awareness capabilities found in relevant industry reports and how these recommendations have been addressed, if applicable. If recommendations have not been addressed fully, the table includes a description of how they should be addressed in Project 2009-02. The following industry reports are considered here[9]:

- 2003 Blackout Final Report
- 2011 Southwest Outage Report
- Real-time Tools Best Practices Task Force

Report Recommendation Mapping	
Report Recommendation	**Applicable Standard(s)**
2003 Blackout Final Report	
Recommendation 1-21, 23-46	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators. Operating Committee to evaluate the real-time operating tools necessary for reliability operation and reliability coordination, including backup capabilities. The committee's report is to address both minimum acceptable capabilities for critical reliability functions and a guide to best practices.	The Operating Committee established the RTBPTF to evaluate real-time operating tools and make recommendations for proposed standards. Project 2009-02 should consider these recommendations as discussed below.
2011 Southwest Outage Report	
Recommendation 1-10, 13-26	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 11 - TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Project 2014-03 developed the proposed definition of Real-time Assessment and proposed TOP-003-3 Requirement R1 which describes the requirements for a data specification that will provide all of the data that a TOP needs in order to fulfill its reliability function. Together, these address capabilities and required data TOPs must have to ensure adequate situational awareness. **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.) **Proposed TOP-003-3, Requirement R1, Part 1.1**:

[9] *All industry reports are available on the 2009-02 Project Page: http://www.nerc.com/pa/Stand/Pages/Project-2009-02-Real-time-Reliability-Monitoring-and-Analysis-Capabilities.aspx.*

	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.
Recommendation 12 - TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2014-03 developed a requirement for the performance of a Real-time Assessment for Transmission Operators. Standards developed in Project 2009-02 will address the adequacy of tools as described in this recommendation. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
Recommendation 27 - TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences.	Proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA) developed in Project 2014-03 specify that identified phase angle limitations must be considered and deal with applying phase angle information. Proposed TOP-002 Requirement R2 specifies that TOPs must have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified in the OPA. Data specification requirements in approved IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3 provide a means for RCs and TOPs to obtain phase angle information. **Proposed Definition: 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.) **Proposed Definition: 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.) **Proposed TOP-002-4** 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.
RTBPTF Report	
S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • **Alarm Tools** • **Telemetry Data Systems** • **Network Topology Processor** • **State Estimator** • **Contingency Analysis**	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. However, prescription of specific tools is not in scope.
S2 - Compile and maintain a list of all bulk electric system elements within RC's area of responsibility.	Not in scope. Reliability objective is accomplished through monitoring and analysis requirements as discussed below.
S3 - Add new requirements and measures pertaining to RC monitoring of the bulk electric system.	Addressed in IRO standards (current and proposed). **IRO-002-2** R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. **IRO-003-2** R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. **Proposed IRO-002-4** 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.
S4 - Develop data-exchange standards.	Addressed in proposed TOP-001-3 and IRO-002-4. **Proposed TOP-001-3** R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area. R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it

	needs data from in order to maintain reliability in its Balancing Authority Area. **Proposed IRO-002-4** 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.
S5 - Develop data-availability standards and a process for trouble resolution and escalation.	Data availability and trouble resolution is addressed in IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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.
S6 - Develop a new weather data requirement related to situational awareness and real-time operational capabilities.	EOP-010-1 covers space weather dissemination. The SAR DT views monitoring other weather information as common utility practice that does not require a reliability standard.
S7 - Specify and measure minimum availability for alarm tools.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the

	RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function). Availability notification for analysis tools is addressed in IRO-008-1, and proposed IRO-008-2 proposed TOP-001-3 from Project 2014-30. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed IRO-008-2** R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
S8 - Specify and measure minimum availability for network topology processor.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S9 - Establish a uniform formal process to determine the "wide area view boundary" and show boundary data/results.	Wide-area is now a defined term. Recommendation has been addressed.
S10 - Develop compliance measures for verification of the usage of "wide-area overview display" visualization tools.	IRO standards revisions have addressed compliance measures.
S11 - Specify and measure minimum availability for state estimator, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S12 - Specify and measure minimum availability for contingency analysis, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S13 - Specify criteria and develop measures for defining contingencies.	Not in scope; Addressed in approved TPL and FAC standards.
S14 - Perform one-hour-ahead power-flow simulations to assess approaching SOL and IROL violations and corresponding measures.	Requirements for assessing pre- and post-contingency system conditions are addressed in Real-time Assessment (RTA) and Operational Planning Analysis (OPA) definitions. Requirements for performing RTA and OPA are contained in

	proposed TOP-001-3, TOP-002-4, IRO-008-2, and approved IRO-008-1. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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. R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed definition** **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.) **Proposed definition** **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.)
S15 - Provide real-time awareness of load-shed capability to address potential or actual IROL violations.	Addressed in proposed EOP-011-1, approved IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

	2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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.
S16 - Require BAs to monitor contingency reserves and calculate contingency reserves at a minimum periodicity of 10 seconds.	BA responsibilities for managing Contingency Reserve are addressed in the approved BAL-002-1 standard which is under revision in Project 2010-014. 1. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.
S17 - Revise the current-day operations requirements to delineate specific, independent requirements for monitoring operating and reactive reserves.	Addressed in VAR-001-4, BAL-002, and proposed IRO-002-4 and TOP-001-3. **VAR-001-4** R4. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. **Proposed IRO-002-4** **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. **Proposed TOP-001-3** 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.
S18 - Establish document plans and procedures for conservative operations.	Addressed in proposed EOP-011-1 Requirement R1. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating

	Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

S19 - Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes.	Addressed in proposed TOP-001-3, and IRO-008-2 and the proposed definitions for Operational Planning Analysis and Real-time Assessment. **Proposed TOP-001-3** R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. 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 an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-008-2** 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. **Proposed definition** **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.) **Proposed definition** **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.)
S20 - Develop formal operating guides (mitigation plans) and measures for each IROL and any SOL or other conditions having a potential impact on reliability.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S21 - Review and update operating guides (mitigation plans) when day-ahead or current day studies indicate the potential need to implement an operating guide.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S22 - Provide temporary operating guides (mitigation plans) with control actions for situations that could affect reliability but that have not been identified previously.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S23 - Develop joint operating guides (mitigation plans) for situations that could require more than one RC or more than one TOP to execute actions.	Addressed in IRO-014-2, proposed IRO-014-3 and proposed IRO-008-2. **IRO-014-2** R1. Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall collectively address the following: ... **Proposed IRO-014-3** 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: ... **Proposed IRO-008-2** 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.
S24 - Develop a formal procedure to document the processes for developing, reviewing, and updating operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S25 - Incorporate verifiable and traceable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates when modifying operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S26 - Write operating guides (mitigation plans) in clear, unambiguous language, leaving nothing to interpretation.	Not in scope. This is administrative in nature.
S27 - State the specific purpose of existence for each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S28 - Summarize the specific situation assessment and address the method of performing the assessment in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S29 - Identify all appropriate preventive and remedial control actions in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S30 - Develop criteria in operating guides (mitigation plans) to support decisions regarding whether a specific control action should be taken.	Not in scope. This is administrative in nature.
S31 - Incorporate on-line tools that utilize on-line data when operating guides (mitigation plans) require calculations.	Not in scope. Recommendation is appropriate as a guideline rather than a reliability standard.
S32 - Make operating guides (mitigation plans) readily available via a quick-access method such as Web-based help, EMS display notes, or on-line help systems.	Not in scope. This is administrative in nature.
S33 - Provide the location, real-time status, and MWs of load available to be shed.	Addressed in proposed EOP-011-1 Requirement R1 Part 1.2.5 and proposed TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

	1.2.6. Reliability impacts of extreme weather conditions. **Proposed TOP-003-3** 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. ...
S34 - Establish documented procedures for the reassessment and re-posturing of the system following an event.	Addressed in proposed TOP-002-4 and IRO-008-2, and approved EOP-005-2 and EOP-006-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ...

	EOP-006-2 R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S35 - Provide information to operators to maintain awareness of the availability and capability of the blackstart generators and transmission restoration paths.	Addressed in approved IRO-010-1, proposed TOP-003-3, proposed IRO-010-2, approved EOP-005-2, and approved EOP-006-2. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... R1.6. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ... R1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit. ... R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **EOP-006-2** R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S36 - Plan and coordinate scheduled outages of blackstart generators and transmission restoration paths.	Addressed in approved EOP-005-2 and proposed IRO-017-1 - Outage Coordination. **EOP-005-2** R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **Proposed IRO-017-1** R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation

	and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: ...
S37 - Maintain a Critical Equipment Monitoring Document to identify tools and procedures for monitoring critical equipment.	Not in scope. This is administrative in nature.
S38 - Maintain event logs pertaining to critical equipment status for a period of one year.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be "installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools". Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S39 - Maintain a Critical Equipment Maintenance and Testing Document identifying tools and procedures for maintenance, modification, and testing of critical equipment.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be "installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools". Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S40 - Monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation.	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and analysis capabilities are not available (i.e., not performing their intended function).

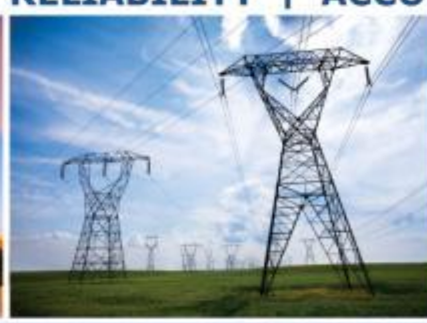
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Justification

Project 2009-02 Real-time Monitoring and Analysis Capabilities

RELIABILITY | ACCOUNTABILITY



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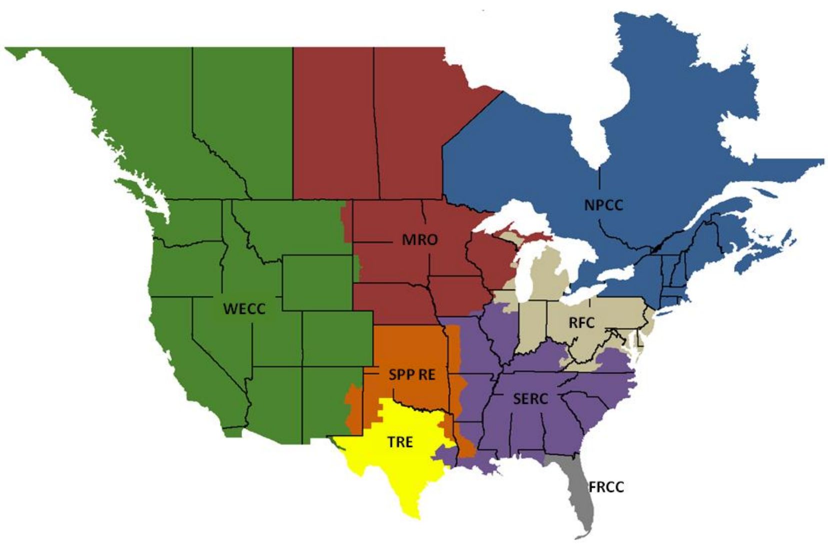
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

In April 2015, the Standards Committee appointed a new Standards Authorization Request (SAR) Drafting Team (SAR DT) for Project 2009-02 Real-time Monitoring and Analysis Capabilities. This project originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). Several new Reliability Standards and defined terms have been approved or filed for approval in the years since Project 2009-02 was initiated, including the standards developed in Project 2014-03 Revisions to TOP and IRO Standards. As a result, many of the original issues identified by the RTBPTF for Project 2009-02 have been addressed. In addition, relevant observations and recommendations have emerged from more recent events on the Bulk Electric System (BES) and operating practices have evolved over time. The SAR DT has reviewed previous work done in Project 2009-02, new standards and defined terms, relevant industry report findings and recommendations including those contained in the 2011 Southwest Outage report, and industry observations and practices relevant to real-time situational awareness to assist in developing a comprehensive SAR.

This white paper describes the SAR DT's approach to developing the SAR and discusses the technical basis for developing Reliability Standards in Project 2009-02. This white paper and the associated SAR together are intended to fully describe the project purpose, industry need, and project scope.

Chapter 1 – Background

FERC Order No. 693[1] highlights the need for a minimum set of capabilities to be available to assist operators in making real-time decisions. The work done by the RTBPTF, which was formed by NERC in response to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, became the basis for the Real-time Monitoring and Analysis Capabilities (RTMAC) standards development project when it was initiated in 2009. Although Reliability Standards affecting the operating reliability of the Bulk Electric System (BES) have improved significantly over the years since first becoming mandatory in 2007, a reliability issue has persisted in the area of real-time situational awareness capabilities as highlighted in BES event reports and an independent review of the NERC Reliability Standards. A review of industry reports and recommendations pertaining to real-time monitoring and analysis capabilities is provided in this document and in the Appendix. These recommendations, along with the FERC Order No. 693 directives, describe the industry need for the current RTMAC standards project.

BES Event Reports

Project 2009-02, like some other Reliability Standards projects, is informed by the lessons learned from past outages. The two significant outages discussed below highlight issues in real-time situational awareness, among other reliability concerns. Many Communications (COM), Transmission Operations (TOP), and Interconnection Reliability Operations (IRO) standards have addressed event report recommendations to improve the way the BES is planned and operated. The scope of Project 2009-02 is intended to include remaining recommendations from the 2003 Blackout Report and the 2011 Southwest Outage Report that pertain to real-time monitoring and analysis capabilities.

2003 Blackout Report

The largest blackout in history to affect North America began on the afternoon of August 14, 2003 and disrupted over 61,800 Megawatts of electric load in the Northeastern U.S. and the Canadian province of Ontario. Severe impacts to electrical service lasted for nearly one week and an estimated 50 million people were affected. A comprehensive investigation conducted by U.S. and Canadian government and industry leaders identified a host of principal and contributing causes, including:

- Failure to maintain adequate reactive power support,
- Failure to ensure operation within secure limits,
- Inadequate vegetation management,
- Inadequate operator training,
- Failure to identify emergency conditions and communicate that status to neighboring systems, and
- Inadequate regional-scale visibility over the Bulk-Power System (BPS).

Among other causes, the 2003 blackout was linked to dysfunction of SCADA/EMS systems. Additionally, investigators pointed out that several deficiencies leading to the 2003 blackout were also identified weaknesses in previous outages, indicating the need for more effective response. Previous post-event reports included recommendations aimed at improving capabilities for visualizing changes to facilities within the system, and for visualizing changes to facilities in neighboring systems that could have a potential impact. A recurring recommendation also focused on providing capabilities for operators to evaluate courses of action. These

[1] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, 72 Fed. Reg. 16416 at P 1660 (Apr. 4, 2007), FERC Stats. And Regs.¶ 31,242, *order on reh'g,* Order No. 693-A, 120 FERC ¶ 61,053 (2007) (Order No. 693).

observations led to the recommendation in the final report of the 2003 blackout for NERC to **evaluate and adopt better real-time tools for operators and reliability coordinators.**[2]

In response, the NERC Operating Committee organized the RTBPTF to study the real-time situational awareness practices in use within the electric power industry and make recommendations concerning the establishment of minimum capabilities necessary for reliable operations. The RTBPTF report *Real-time Tools Survey Analysis and Recommendations,*[3] completed in 2008*,* is the result of extensive information gathering and analysis and includes recommendations for new or enhanced Reliability Standards, operating guides, and areas for further analysis. This report became a basis for initiating the Real-time Monitoring and Analysis Capabilities project in 2009.

Although exhaustive and comprehensive, some of the RTBPTF recommendations go beyond the scope of situational awareness monitoring and capabilities. In addition, many other recommendations have been addressed in other subsequent standards projects. The appendix provides a description of RTBPTF report recommendations and the SAR DT's determination of applicability within the scope of Project 2009-02.

An early Concept White Paper describing potential performance, availability, quality, and maintenance parameters based on the RTBPTF Report was developed in 2011. The SAR DT reviewed the white paper and confirmed that, due to significant changes to Reliability Standards and operating practices since it was drafted, the 2011 Concept White Paper is no longer relevant to the current effort in Project 2009-02.

2011 Southwest Outage Report

Like the 2003 blackout in the northeast, the blackout that occurred in the southwest in September 2011 was partly due to, or exacerbated by, inadequate real-time situational awareness. On the afternoon of September 8, 2011, the loss of a single 500 kV line led to widespread cascading outages affecting 2.7 million customers in Arizona, Southern California, and Baja, Mexico. Inadequate operations planning was a significant factor in the failure to maintain a secure N-1 state. However, the report also highlighted several concerns with entities and their ability to monitor, identify, and plan for the next most critical contingency in real-time.[4]

Project 2014-03 - Revisions to TOP and IRO Standards addressed many of the recommendations contained in the 2011 Southwest Outage Report related to operations planning and real-time situational awareness. A complete description is provided in the Southwest Outage Report mapping document for Project 2014-03.[5] Revised definitions and performance requirements for Real-time Assessments and Operational Planning Analysis and proposed requirements for developing and implementing Operating Plans to prevent and mitigate operating limit exceedances address most of the real-time situational awareness recommendations from the report. However some recommendations contain aspects pertaining to real-time capabilities that should be considered in Project 2009-02, as described in the appendix. Accordingly, Project 2009-02 will develop requirements to address remaining recommendations as described in the following chapter.

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[2] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* Recommendation 22*,* available at http://www.nerc.com/pa/rrm/ea/2003%20Blackout%20Final%20Report/Forms/AllItems.aspx.

[3] *Real-Time Tools Survey Analysis and Recommendations* (March 13, 2008), available at http://www.nerc.com/comm/OC/Realtime%20Tools%20Best%20Practices%20Task%20Force%20RTBPTF%2020/Real-Time%20Tools%20Survey%20Analysis%20and%20Recommendations.pdf.

[4] *Arizona-Southern California Outages on September 8, 2011* (April 2012), available at http://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf.

[5] See the project page for 2014-03, available at http://www.nerc.com/pa/stand/pages/project-2014-03-revisions-to-top-and-iro-standards.aspx.

FERC Directives

In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to operators.[6] FERC indicated that the intent of the directive is to ensure operating entities have adequate tools to perform their real-time reliability functions.[7]

- P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.*
- P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.*
- P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.*

Independent Experts Review Project (IERP) Report

In 2013, NERC retained a team of five industry experts to assess the quality of the enforceable body of standards and make recommendations for improvements that could be implemented by NERC and the industry.[8] Among the recommendations made by the panel of experts was the identification of potential risks to reliability that may not be adequately addressed in Reliability Standards. The report recommended resuming development of the Real-time Monitoring and Analysis Capabilities standards project.

Proposed TOP and IRO Standards

Since Project 2009-02 was initiated in 2009, many standards and definitions have been revised or developed that address real-time situational awareness issues. In particular, the revised TOP and IRO standards in Project 2014-03, which are pending regulatory approval, include key provisions for real-time situational awareness and operations planning. In reviewing the RTBPTF report recommendations for applicability in the current Project 2009-02 effort, the SAR DT considered the Project 2014-03 standards as noted in the Appendix.

The proposed TOP and IRO standards in Project 2014-03 provide requirements for performing monitoring and analysis through the definition of Real-time Assessment, Operational Planning Analysis, and the relevant requirements. Accordingly, additional requirements to perform monitoring or analysis will not be included in the scope for Project 2009-02. Furthermore, requirements for data exchange to support real-time monitoring and analysis will not be included in scope for Project 2009-02 because they are addressed through data specification requirements in IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3.

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[6] Order No. 693 at P 905 (approving IRO-002-1 and directing modifications) and P 1665 (approving TOP-006-1 and directing modifications.

[7] Additionally, in approving VAR-001-1 - Voltage and Reactive Control, the Commission directed NERC to develop modifications to the standard to require periodic performance of voltage stability analysis to assist in real-time operations. The commission clarified that this could be accomplished through online tools where available, or offline simulation tools.

- §1875: *...[w]e direct the ERO, through its Reliability Standards development process, ...to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.*

VAR-001 was revised in the Project 2013-04, however the revised standard did not include a requirement for periodic performance of voltage stability analysis because voltage stability analysis is performed per SOL Methodology developed under FAC standards.

[8] See The Standards Independent Experts Review Project report. Available at www.nerc.com /pa/Stand/_layouts/xlviewer.aspx?id=/pa/Stand/Documents/P81_and%20IERP_Recommendations_for_Retirement_010815.xlsx.

Technical Conference

NERC and the SAR DT held a Technical Conference in Atlanta on June 4, 2015, to obtain industry input on reliability issues to be addressed in the proposed project. Participant subject matter experts representing a diverse mix of regional and functional entities shared their perspectives on the use of real-time situational awareness capabilities for reliable operations. There was consensus that many RTBPTF recommendations have been addressed in current or proposed TOP and IRO standards. However, Technical Conference participants agreed that issues identified by the RTBPTF pertaining to availability and information quality of real-time monitoring and analysis capabilities were still relevant.

Chapter 2 – Project Scope

The SAR DT has reviewed all recommendations from the RTBPTF and relevant recommendations from event reports, along with the existing body of standards, to identify remaining issues that should be in the scope for Project 2009-02. Table 1 below shows the resulting recommendations to be addressed. Additionally, the project will address outstanding FERC directives discussed in the preceding chapter.

Table 1: Report Recommendations to Address in Project 2009-02

Source	Recommendation	Discussion	Applicable Entity
2003 Blackout Report	Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators.	Project 2009-02 will develop requirements for real-time reliability monitoring and analysis capabilities to address issues not already addressed in other Reliability Standards. RTBPTF report recommendations will be considered in development.	RC, TOP, BA
2011 Southwest Outage Report	Recommendation 12 - [entities] should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2009-02 will develop requirements to improve the adequacy and operation of real-time monitoring and analysis capabilities. Requirements addressing the frequency that real-time tools run are contained in other standards and are not in the scope of this project.	RC, TOP, BA
RTBPTF Report	S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • Alarm Tools • Telemetry Data Systems • Network Topology Processor • State Estimator • Contingency Analysis	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. Prescription of specific tools is not in scope. Project approach is discussed below.	RC, TOP, BA as discussed below
RTBPTF Report	S7 - S8, S11-S12, S40 - Availability of various monitoring and analysis capability processes	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring ~~and analysis~~ capabilities are not available (i.e., not performing their intended function).	RC, TOP, BA

Project Purpose and Approach

Project 2009-02 will develop requirements for real-time monitoring and analysis capabilities used by operators in support of reliable System operations. Functional requirements for performing *monitoring* and *analysis* tasks are well established in Reliability Standards as discussed throughout this white paper. However, reliability could be improved by:

- Developing a common understanding of *monitoring* as it applies to real-time situational awareness of the BES,
- Providing operators with indication(s) of the quality of information being provided by *monitoring* and *analysis* capabilities, and

- Providing operators with notification(s) during unplanned loss of *monitoring* ~~and *analysis*~~ capabilities.

Project 2009-02 will develop requirements and definition(s), as needed, to accomplish these reliability objectives as discussed.

Real-time Situational Awareness Concept

From the RTBPTF Report:

> *Situational awareness, as RTBPTF understands it, means ensuring that accurate information on current system conditions, including the likely effects of future contingencies, is continuously available in a form that allows operators to quickly grasp and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations.*

The Project 2009-02 SAR DT believes that situational awareness encompasses two broad capabilities: monitoring and analysis. To be effective in supporting real-time situational awareness, monitoring and analysis must:

- Be performed with sufficient frequency to allow operators to understand operating conditions and take corrective actions when necessary,
- Provide awareness of information quality to allow operators to assess the accuracy of information being received on system conditions and take corrective actions when necessary, and
- Indicate when monitoring or analysis processes are not operating normally or are unavailable in order to provide operator awareness of the accuracy of the information being provided.

Project 2009-02 will develop new requirements and definition(s), as needed, that support this concept of situational awareness without duplicating aspects that are already addressed in the existing and proposed body of Reliability Standards. As discussed in the preceding chapter, requirements for the Reliability Coordinator (RC), Transmission Operator (TOP), and Balancing Authority (BA) to perform monitoring and analysis are covered under existing and proposed TOP and IRO standards. Therefore, Project 2009-02 will focus on developing requirements to address information quality and operator awareness of real-time monitoring and analysis capabilities. Table 2 shows reliability objectives that should be addressed in requirements for this project.

Monitoring

Monitoring BES facilities in real-time is a primary function of the RCs, TOPs, and BAs and is addressed in existing and proposed TOP and IRO standards. For RCs, proposed IRO-002-4 states:

> *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.*

For TOPs and BAs, proposed TOP-001-3 states:

> *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.

The SAR DT understands *monitoring* capabilities may include both alarming and information visualization. Project 2009-02 will aim to develop a consistent understanding of *monitoring* within the industry. The project will also address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of information being provided by a monitoring system, and indication when a monitoring system is not operating normally.

Analysis

The *analysis* component of the Real-time situational awareness concept is described by the definition of Real-time Assessment, which is pending FERC approval along with the proposed TOP and IRO standards. The proposed definition is as follows:

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.)*

Requirements for performing Real-time Assessments are contained in proposed IRO-008-2 and TOP-001-3:

Proposed IRO-008-2
R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed TOP-001-3
R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

The SAR DT believes the proposed definition of Real-time Assessment and the requirements in proposed IRO-008-2 and TOP-001-3 provide RCs and TOPs with flexibility to determine which real-time tools, such as State Estimator, Contingency Analysis, and Stability Applications, are necessary to meet their real-time reliability functions. Consequently, prescriptive requirements for real-time tools are not in scope for Project 2009-02.

The project will address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of the analysis ~~provided by~~used in ~~a~~ Real-time Assessments~~ and notification when Real-time Assessment capabilities are not available~~.

Table 2: Project 2009-02 Reliability Objectives		
	Monitoring Capabilities	**Analysis Capabilities**
Quality	Provide operator with indication of information quality and procedures to address data quality issues.	Provide operator with indication of information quality and procedures to address analysis quality issues.

Availability	Provide operator with notification any time monitoring system is not operating normally.	~~Provide operator with notification any time Real-time Assessment capabilities are not available.~~ N/A

Appendix – Report Recommendations

The table below contains recommendations for improved real-time situational awareness capabilities found in relevant industry reports and how these recommendations have been addressed, if applicable. If recommendations have not been addressed fully, the table includes a description of how they should be addressed in Project 2009-02. The following industry reports are considered here[9]:

- 2003 Blackout Final Report
- 2011 Southwest Outage Report
- Real-time Tools Best Practices Task Force

Report Recommendation Mapping	
Report Recommendation	**Applicable Standard(s)**
2003 Blackout Final Report	
Recommendation 1-21, 23-46	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators. Operating Committee to evaluate the real-time operating tools necessary for reliability operation and reliability coordination, including backup capabilities. The committee's report is to address both minimum acceptable capabilities for critical reliability functions and a guide to best practices.	The Operating Committee established the RTBPTF to evaluate real-time operating tools and make recommendations for proposed standards. Project 2009-02 should consider these recommendations as discussed below.
2011 Southwest Outage Report	
Recommendation 1-10, 13-26	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 11 - TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Project 2014-03 developed the proposed definition of Real-time Assessment and proposed TOP-003-3 Requirement R1 which describes the requirements for a data specification that will provide all of the data that a TOP needs in order to fulfill its reliability function. Together, these address capabilities and required data TOPs must have to ensure adequate situational awareness. **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.) **Proposed TOP-003-3, Requirement R1, Part 1.1**:

[9] *All industry reports are available on the 2009-02 Project Page: http://www.nerc.com/pa/Stand/Pages/Project-2009-02-Real-time-Reliability-Monitoring-and-Analysis-Capabilities.aspx.*

	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.
Recommendation 12 - TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2014-03 developed a requirement for the performance of a Real-time Assessment for Transmission Operators. Standards developed in Project 2009-02 will address the adequacy of tools as described in this recommendation. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
Recommendation 27 - TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences.	Proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA) developed in Project 2014-03 specify that identified phase angle limitations must be considered and deal with applying phase angle information. Proposed TOP-002 Requirement R2 specifies that TOPs must have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified in the OPA. Data specification requirements in approved IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3 provide a means for RCs and TOPs to obtain phase angle information. **Proposed Definition: 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.) **Proposed Definition: 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.) **Proposed TOP-002-4** 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.
RTBPTF Report	
S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • **Alarm Tools** • **Telemetry Data Systems** • **Network Topology Processor** • **State Estimator** • **Contingency Analysis**	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. However, prescription of specific tools is not in scope.
S2 - Compile and maintain a list of all bulk electric system elements within RC's area of responsibility.	Not in scope. Reliability objective is accomplished through monitoring and analysis requirements as discussed below.
S3 - Add new requirements and measures pertaining to RC monitoring of the bulk electric system.	~~Addresses~~ Addressed in IRO standards (current and proposed). **IRO-002-2** R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. **IRO-003-2** R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. **Proposed IRO-002-4** 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.
S4 - Develop data-exchange standards.	Addressed in proposed TOP-001-3 and IRO-002-4. **Proposed TOP-001-3** R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.

	R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area. **Proposed IRO-002-4** 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.
S5 - Develop data-availability standards and a process for trouble resolution and escalation.	Data availability and trouble resolution is addressed in IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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.
S6 - Develop a new weather data requirement related to situational awareness and real-time operational capabilities.	EOP-010-1 covers space weather dissemination. The SAR DT views monitoring other weather information as common utility practice that does not require a reliability standard.
S7 - Specify and measure minimum availability for alarm tools.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and

	alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and~~,~~ alarming~~, and analysis~~ tools are not available (i.e. not performing their intended function). Availability notification for analysis tools is addressed in IRO-008-1, and proposed IRO-008-2 proposed TOP-001-3 from Project 2014-30. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed IRO-008-2** R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
S8 - Specify and measure minimum availability for network topology processor.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and ~~,~~ alarming~~, and analysis~~ tools are not available (i.e. not performing their intended function).
S9 - Establish a uniform formal process to determine the “wide area view boundary” and show boundary data/results.	Wide-area is now a defined term. Recommendation has been addressed.
S10 - Develop compliance measures for verification of the usage of “wide-area overview display” visualization tools.	IRO standards revisions have addressed compliance measures.
S11 - Specify and measure minimum availability for state estimator, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and~~,~~ alarming~~, and analysis~~ tools are not available (i.e. not performing their intended function).
S12 - Specify and measure minimum availability for contingency analysis, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation to provide operator awareness when key monitoring~~,~~ and alarming~~, and analysis~~ tools are not available (i.e. not performing their intended function).
S13 - Specify criteria and develop measures for defining contingencies.	Not in scope; Addressed in approved TPL and FAC standards.

S14 - Perform one-hour-ahead power-flow simulations to assess approaching SOL and IROL violations and corresponding measures.	Requirements for assessing pre- and post-contingency system conditions are addressed in Real-time Assessment (RTA) and Operational Planning Analysis (OPA) definitions. Requirements for performing RTA and OPA are contained in proposed TOP-001-3, TOP-002-4, IRO-008-2, and approved IRO-008-1. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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. R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed definition** **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.) **Proposed definition** **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.)
S15 - Provide real-time awareness of load-shed capability to address potential or actual IROL violations.	Addressed in proposed EOP-011-1, approved IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s);

	2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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.
S16 - Require BAs to monitor contingency reserves and calculate contingency reserves at a minimum periodicity of 10 seconds.	BA responsibilities for managing Contingency Reserve are addressed in the approved BAL-002-1 standard which is under revision in Project 2010-014. 1. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.
S17 - Revise the current-day operations requirements to delineate specific, independent requirements for monitoring operating and reactive reserves.	Addressed in VAR-001-4, BAL-002, and proposed IRO-002-4 and TOP-001-3. **VAR-001-4** R4. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. **Proposed IRO-002-4** **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. **Proposed TOP-001-3** 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.
S18 - Establish document plans and procedures for conservative operations.	Addressed in proposed EOP-011-1 Requirement R1. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-

	reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

S19 - Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes.	Addressed in proposed TOP-001-3, and IRO-008-2 and the proposed definitions for Operational Planning Analysis and Real-time Assessment. **Proposed TOP-001-3** R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. 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 an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-008-2** 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. **Proposed definition** **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.) **Proposed definition** **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.)
S20 - Develop formal operating guides (mitigation plans) and measures for each IROL and any SOL or other conditions having a potential impact on reliability.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S21 - Review and update operating guides (mitigation plans) **when day-ahead or current day studies indicate the potential need to implement an operating guide.**	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S22 - Provide temporary operating guides (mitigation plans) with control actions for situations that could affect reliability but that have not been identified previously.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S23 - Develop joint operating guides (mitigation plans) for situations that could require more than one RC or more than one TOP to execute actions.	Addressed in IRO-014-2, proposed IRO-014-3 and proposed IRO-008-2. **IRO-014-2** R1. Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall collectively address the following: ... **Proposed IRO-014-3** 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: ... **Proposed IRO-008-2** 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.
S24 - Develop a formal procedure to document the processes for developing, reviewing, and updating operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S25 - Incorporate verifiable and traceable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates when modifying operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S26 - Write operating guides (mitigation plans) in clear, unambiguous language, leaving nothing to interpretation.	Not in scope. This is administrative in nature.
S27 - State the specific purpose of existence for each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S28 - Summarize the specific situation assessment and address the method of performing the assessment in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S29 - Identify all appropriate preventive and remedial control actions in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S30 - Develop criteria in operating guides (mitigation plans) to support decisions regarding whether a specific control action should be taken.	Not in scope. This is administrative in nature.
S31 - Incorporate on-line tools that utilize on-line data when operating guides (mitigation plans) require calculations.	Not in scope. Recommendation is appropriate as a guideline rather than a reliability standard.
S32 - Make operating guides (mitigation plans) readily available via a quick-access method such as Web-based help, EMS display notes, or on-line help systems.	Not in scope. This is administrative in nature.
S33 - Provide the location, real-time status, and MWs of load available to be shed.	Addressed in proposed EOP-011-1 Requirement R1 Part 1.2.5 and proposed TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

	1.2.6. Reliability impacts of extreme weather conditions. **Proposed TOP-003-3** 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. ...
S34 - Establish documented procedures for the reassessment and re-posturing of the system following an event.	Addressed in proposed TOP-002-4 and IRO-008-2, and approved EOP-005-2 and EOP-006-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ...

	EOP-006-2 R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S35 - Provide information to operators to maintain awareness of the availability and capability of the blackstart generators and transmission restoration paths.	Addressed in approved IRO-010-1, proposed TOP-003-3, proposed IRO-010-2, approved EOP-005-2, and approved EOP-006-2. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... R1.6. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ... R1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit. ... R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **EOP-006-2** R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S36 - Plan and coordinate scheduled outages of blackstart generators and transmission restoration paths.	Addressed in approved EOP-005-2 and proposed IRO-017-1 - Outage Coordination. **EOP-005-2** R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **Proposed IRO-017-1** R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation

	and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: ...
S37 - Maintain a Critical Equipment Monitoring Document to identify tools and procedures for monitoring critical equipment.	Not in scope. This is administrative in nature.
S38 - Maintain event logs pertaining to critical equipment status for a period of one year.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be “installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools”. Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S39 - Maintain a Critical Equipment Maintenance and Testing Document identifying tools and procedures for maintenance, modification, and testing of critical equipment.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be “installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools”. Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S40 - Monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation.	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and analysis capabilities are not available (i.e., not performing their intended function).

Violation Risk Factor and Violation Severity Level Justifications

Project 2009-02 Real-time Monitoring and Analysis Capabilities

This document provides the Standard Drafting Team's (SDT) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in Project 2009-02.

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 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.

FERC Violation Risk Factor Guidelines

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

The Commission seeks to ensure that VRFs 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 VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of VRFs 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 VRF 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

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

FERC's 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 Justification

The requirements in IRO-018-1 and TOP-010-1 were developed to address certain issues related to the Real-time monitoring and analysis capabilities used by operators of the BES. IRO-018-1 contains five requirements applicable to Reliability Coordinators (RCs), while TOP-010-1 contains seven analogous requirements for Transmission Operators (TOPs) and Balancing Authorities (BAs). A Medium VRF is proposed for all requirements in both standards according to the guidelines as explained below.

VRF Justifications – IRO-018-1 (R1-R5) and TOP-010-1 (R1-R7)	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A. The requirements are not directly connected to conclusions from the 2003 Blackout, but rather address specific recommendations from NERC Technical Committees.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard. The requirements have no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. These are new requirements. The VRFs in IRO-018-1 are consistent with those contained in TOP-010-1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A VRF of Medium is consistent with the NERC VRF definition. The requirements in IRO-018-1 and TOP-010-1 address issues related to the quality and availability of monitoring and analysis capabilities used by RCs, TOPs, and BAs in maintaining reliable operations. Violation of any of these requirements could directly affect the ability to effectively monitor and control the Bulk Electric System. However, violation of any of these requirements is unlikely to lead to Bulk Electric System instability, separation, or cascading failures. Therefore, a VRF of Medium is appropriate.

VRF Justifications – IRO-018-1 (R1-R5) and TOP-010-1 (R1-R7)	
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. Each requirement contains one objective, therefore a single VRF is assigned to each requirement.

VSL Justification

Proposed VSLs – IRO-018-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 and Part 1.2.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 and Part 1.2; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to

			perform its Real-time monitoring and Real-time Assessments.

VSL Justifications – IRO-018-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – IRO-018-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its Real-time monitoring and Real-time Assessments.

VSL Justifications – IRO-018-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	The proposed VSL is worded consistently with the corresponding requirement.

Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – IRO-018-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 and Part 3.2.	The Reliability Coordinator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 and Part 3.2.; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure

			to maintain the quality of any analysis used in its Real-time Assessments.

VSL Justifications – IRO-018-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – IRO-018-1, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.

VSL Justifications – IRO-018-1, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to 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 proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – IRO-018-1, R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not utilize an independent alarm

			process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

VSL Justifications – IRO-018-1, R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any

		of the elements listed in Part 1.1 and Part 1.2.	of the elements listed in Part 1.1 and Part 1.2; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.

VSL Justifications – TOP-010-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 and Part 2.2.	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 and Part 2.2.; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.

VSL Justifications – TOP-010-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1	There is no prior compliance obligation related to the subject of this standard.

Violation Severity Level Assignments Should Not Have the Unintended 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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4	The proposed VSL is not based on a cumulative number of violations.

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

Proposed VSLs – TOP-010-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its Real-time monitoring and Real-time Assessments.

VSL Justifications – TOP-010-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of	There is no prior compliance obligation related to the subject of this standard.

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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A	The proposed VSL is not based on a cumulative number of violations.

Cumulative Number of Violations	

Proposed VSLs – TOP-010-1, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its analysis functions and Real-time monitoring.

VSL Justifications – TOP-010-1, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include one of the elements listed in Part 5.1 and Part 5.2.	The Transmission Operator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include any of the elements listed in Part 5.1 and Part 5.2.; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments.

VSL Justifications – TOP-010-1, R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of	There is no prior compliance obligation related to the subject of this standard.

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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A	The proposed VSL is not based on a cumulative number of violations.

Cumulative Number of Violations	

Proposed VSLs – TOP-010-1, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.

VSL Justifications – TOP-010-1, R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

VSL Justifications – TOP-010-1, R7	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Order No. 693 Citation	Directive/Guidance	Resolution
P 905-906	Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.	Proposed IRO-018-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the Reliability Coordinator's (RC) monitoring and analysis capabilities. The monitoring and analysis capabilities required by proposed IRO-018-1 and other IRO standards discussed below ensure RCs have the capabilities to maintain Real-time situational awareness. **Monitoring Capabilities** Requirements R1 and R2 address the quality of the Real-time data needed by the RC to perform its monitoring and Real-time Assessments. Each RC is required to implement a documented procedure for addressing Real-time data quality issues, including invalid or time-late data, and must provide System Operators with information to indicate the quality of data received. Requirement R5 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring RCs to use an independent alarm process monitor. Requirements for the RC to perform Real-time monitoring are specified in currently-enforceable IRO-002-2, IRO-003-2, and proposed IRO-002-4 from Project 2014-03. ***Proposed IRO-018-1*** **R1.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time

Order No. 693 Citation	Directive/Guidance	Resolution
		monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to: **1.1.1.** Data outside of a prescribed data range; **1.1.2.** Analog data not updated within a predetermined time period; **1.1.3.** Data entered manually to override telemetered information; and **1.1.4.** Data otherwise identified as invalid or suspect. **1.2.** Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data. **R2.** Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. **R5.** Each Reliability Coordinator shall utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***Currently-enforceable IRO-002-2*** **R5.** Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be

Order No. 693 Citation	Directive/Guidance	Resolution
		critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. ***Currently-enforceable IRO-003-2*** **R1.** Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. ***Proposed IRO-002-4 (pending regulatory approval)*** **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. **<u>Analysis Capabilities</u>** Requirements R3 and R4 address the quality of the analysis used by the RC to perform its Real-time Assessments. Each RC is required to implement a documented procedure to maintain the quality of the analysis used in its Real-time Assessments and must provide System Operators with information to indicate the quality of this analysis.

Order No. 693 Citation	Directive/Guidance	Resolution
		Requirements for the RC to perform Real-time Assessments are specified in currently-enforceable IRO-008-1 and proposed IRO-008-2. ***Proposed IRO-018-1*** **R3.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: **3.1.** Criteria for evaluating the quality of any analysis used in its Real-time Assessments; and **3.2.** Actions to resolve quality deficiencies in any analysis used in its Real-time Assessments. **R4.** Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. ***Currently-enforceable IRO-008-1*** **R2.** Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. ***Revised definition of Real-time Assessment (pending regulatory approval)*** 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

Order No. 693 Citation	Directive/Guidance	Resolution
		identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) ***Proposed IRO-008-2 (pending regulatory approval)*** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
P 1660	We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.	Proposed TOP-010-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the monitoring and analysis capabilities used by Transmission Operators (TOPs) and Balancing Authorities (BAs). The monitoring and analysis capabilities required by proposed TOP-010-1 and other TOP standards discussed below ensure TOPs and BAs have the capabilities to maintain Real-time situational awareness. **<u>Monitoring Capabilities</u>** Requirements R1 through R4 address the quality of the Real-time data needed by TOPs and BAs to perform their Real-time monitoring and Real-time analysis. Each TOP and BA is required to implement a documented procedure for addressing Real-time data quality issues, including invalid or time-late data, and must provide System Operators with information to indicate the quality of data received. Requirement R7 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring TOPs and BAs to use an independent alarm process monitor. Requirements for TOPs to perform Real-time monitoring are specified in currently-enforceable TOP-006-2 and proposed TOP-001-3 from Project 2014-03.

Order No. 693 Citation	Directive/Guidance	Resolution
		Requirements for BAs to perform Real-time monitoring are specified in currently-enforceable TOP-006-2, proposed TOP-001-3 from Project 2014-03, and BAL standards. ***Proposed TOP-010-1*** **R1.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to: **1.1.1.** Data outside of a prescribed data range; **1.1.2.** Analog data not updated within a predetermined time period; **1.1.3.** Data entered manually to override telemetered information; and **1.1.4.** Data otherwise identified as invalid or suspect. **1.2.** Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data. **R2.** Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: **2.1** Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to: **2.1.1.** Data outside of a prescribed data range;

Order No. 693 Citation	Directive/Guidance	Resolution
		2.1.2. Analog data not updated within a predetermined time period; **2.1.3.** Data entered manually to override telemetered information; and **2.1.4.** Data otherwise identified as invalid or suspect. **2.2** Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data. **R3.** Each Transmission Operator shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. **R4.** Each Balancing Authority shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. **R7.** Each Transmission Operator and Balancing Authority shall utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***Currently-enforceable TOP-006-2*** **R1.** Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. **1.1.** - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2.** - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission

Order No. 693 Citation	Directive/Guidance	Resolution
		Operators of all generation and transmission resources available for use. ***Proposed TOP-001-3 (pending regulatory approval)*** **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. **<u>Analysis Capabilities</u>** Requirements R5 and R6 address the quality of the analysis used by the TOP to perform its Real-time Assessments. Each TOP is required to implement a documented procedure to maintain the quality of the analysis used in its Real-time Assessments and must provide System Operators with information to indicate the quality of this analysis. Requirements for the TOP to perform Real-time Assessments are specified in proposed TOP-003-3 from Project 2014-03.

Order No. 693 Citation	Directive/Guidance	Resolution
		Proposed TOP-010-1 **R5.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: **5.1.** Criteria for evaluating the quality of any analysis used in its Real-time Assessments; and **5.2.** Actions to resolve quality deficiencies in any analysis used in its Real-time Assessments. **R6.** Each Transmission Operator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. ***Proposed definition of Real-time Assessment (pending regulatory approval)*** 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.) ***Proposed TOP-001-3 (pending regulatory approval)*** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
P 1875	...[w]e direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1	The directive was considered in developing the scope of Project 2009-02. NERC believes currently enforceable IRO standards,

Order No. 693 Citation	Directive/Guidance	Resolution
	to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.	proposed TOP and IRO standards, and currently-enforceable VAR standards address the directive as discussed below. Accordingly, additional requirements were not developed in Project 2009-02. RCs and TOPs are required to periodically perform Real-time Assessments consisting of an evaluation of system conditions "to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions." Entities must use whatever analysis is necessary to obtain an evaluation of system conditions, which may include real-time voltage stability analysis. Real-time Assessments assist operators in maintaining operations within established SOLs and IROLs, to include voltage stability criteria. Requirements for performing Real-time Assessments are contained in currently-enforceable IRO-008-1 and proposed IRO-008-2 and TOP-001-3 Reliability Standards as discussed above. VAR-001-1 was revised in Project 2013-04. The resulting standard, VAR-001-4, did not include an explicit requirement for periodic performance of voltage stability analysis because "such analysis would be performed pursuant to the SOL methodology developed under FAC standards."[1] VAR-001-4 requirement R1 specifies the TOP must establish a system voltage schedule as part of its plan to operate within SOLs and IROLs. ***Currently-enforceable VAR-001-4*** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an

[1] Reliability Standard VAR-001-4.1, Guidelines and Technical Basis section, page 13. Available at: http://www.nerc.com/pa/Stand/Reliability%20Standards/VAR-001-4.1.pdf

Order No. 693 Citation	Directive/Guidance	Resolution
		associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. **1.1.** Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

Standards Announcement
Reminder
Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities
IRO-018-1 and TOP-010-1

Initial Ballots and Non-binding Polls Open through November 9, 2015

Now Available

Initial ballots for **IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities** and **TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, November 9, 2015**.

Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standards and non-binding polls by clicking here. If you experience any difficulties in using the electronic form, contact Nasheema Santos.

Next Steps

The drafting team will consider all comments received during the formal comment period and determine the next steps for 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, Mark Olson (via email), or at (404) 446-9760.

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Standards Announcement

Project 2009-02
Real-time Monitoring and Analysis Capabilities
IRO-018-1 and TOP-010-1

Formal Comment Period Open through November 9, 2015
Ballot Pools Forming through October 23, 2015

Now Available

A 45-day formal comment period for **IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities** and **TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities** is open through **8 p.m. Eastern, Monday, November 9, 2015**.

Commenting
Use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, contact Nasheema Santos. 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, October 23, 2015.** Registered Ballot Body members may join the ballot pools 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 mailto:EROhelpdesk@nerc.net (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps
Initial ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 30 – November 9, 2015**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

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Standards Announcement

Project 2009-02
Real-time Monitoring and Analysis Capabilities
IRO-018-1 and TOP-010-1

Formal Comment Period Open through November 9, 2015
Ballot Pools Forming through October 23, 2015

Now Available

A 45-day formal comment period for **IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities** and **TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities** is open through **8 p.m. Eastern, Monday, November 9, 2015**.

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Next Steps

Initial ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 30 – November 9, 2015**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

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Standards Announcement

Project 2009-02
Real-time Monitoring and Analysis Capabilities
IRO-018-1 and TOP-010-1

Initial Ballots and Non-binding Polls Results

Now Available

Initial ballots for **Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels concluded **8 p.m. Eastern, November 9, 2015.**

The standards are as follows:

- IRO-018-1 - **Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities**
- TOP-010-1 - **Real-time Reliability Monitoring and Analysis Capabilities**

The standards did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides the detailed results.

	Ballot	Non-binding Poll
Standard	Quorum / Approval	Quorum / Supportive Opinions
IRO-018-1	84.59% / 47.38%	82.71% / 54.61%
TOP-010-1	84.49% / 48.00%	83.94% / 56.25%

Next Steps

The drafting team will consider all comments received during the formal comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/33)
Ballot Name: 2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 IN 1 ST
Voting Start Date: 10/30/2015 12:01:00 AM
Voting End Date: 11/9/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 247
Total Ballot Pool: 292
Quorum: 84.59
Weighted Segment Value: 47.36

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	73	1	24	0.511	23	0.489	0	18	8
Segment: 2	10	0.7	2	0.2	5	0.5	0	1	2
Segment: 3	68	1	20	0.455	24	0.545	0	12	12
Segment: 4	21	1	8	0.5	8	0.5	0	3	2
Segment: 5	63	1	22	0.564	17	0.436	0	12	12
Segment: 6	47	1	15	0.455	18	0.545	0	6	8
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	0	0	1	0.1	0	1	0
Segment:	2	0.1	0	0	1	0.1	0	0	1

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9									
Segment: 10	6	0.4	3	0.3	1	0.1	0	2	0
Totals:	292	6.3	94	2.984	98	3.316	0	55	45

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		Abstain	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		Abstain	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Negative	Third-Party Comments
1	Berkshire Hathaway Energy -	Terry Harbour		Negative	Third-Party Comments

	MidAmerican Energy Co.				
1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Donald Watkins		Abstain	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Abstain	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	Third-Party Comments
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		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		Affirmative	N/A
1	Georgia	Jason Snodgrass		Abstain	N/A

	Transmission Corporation				
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	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		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		None	N/A
1	Long Island Power Authority	Robert Ganley		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
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		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
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		Negative	Comments Submitted
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	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	PHI - Potomac Electric Power Co.	David Thorne		Negative	Third-Party Comments
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	John Walker		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
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		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		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		Negative	Comments Submitted
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
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		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System	Leonard Kula		Negative	Comments Submitted

	Operator				
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		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	Comments Submitted
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		None	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Abstain	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	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
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	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	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		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Abstain	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		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	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	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	Third-Party Comments
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	Comments Submitted
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	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		None	N/A

3	PHI - Potomac Electric Power Co.	Mark Yerger		Negative	Third-Party Comments
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Thomas Ward		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Third-Party Comments
3	Puget Sound Energy, Inc.	Andrea Basinski		None	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	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		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		Abstain	N/A
3	Turlock Irrigation District	James Ramos		None	N/A

3	WEC Energy Group, Inc.	James Keller		Negative	Third-Party Comments
3	Westar Energy	Bo Jones		Negative	Comments Submitted
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		Abstain	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		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	Bill Hughes	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Abstain	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		None	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Abstain	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	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		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	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	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Abstain	N/A
5	Bonneville Power Administration	Francis Halpin		Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of	Jim Nail		Affirmative	N/A

	Independence, Power and Light Department				
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Third-Party Comments
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	Dominion - Dominion Resources, Inc.	Randi Heise		Negative	Third-Party Comments
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		None	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Affirmative	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A

5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		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	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		Negative	Third-Party Comments
5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Wayne Sipperly		Negative	Third-Party Comments
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District	Sam Nietfeld		Affirmative	N/A

	No. 1 of Snohomish County				
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	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		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Third-Party Comments
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	WEC Energy Group,	Linda Horn		Negative	Third-Party

	Inc.				Comments
5	Westar Energy	stephanie johnson		Negative	Comments Submitted
6	AEP - AEP Marketing	Edward P Cox		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		None	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	Comments Submitted
6	Bonneville Power Administration	Alex Spain		Abstain	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Negative	Third-Party Comments
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Earle Saunders		None	N/A
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy		Negative	Comments Submitted

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	Negative	Third-Party Comments
6	Iberdrola - New York State Electric and Gas Corporation	Julie King		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Shivaz Chopra		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	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		Negative	Third-Party Comments
6	Omaha Public Power District	Mark Trumble		Negative	Third-Party Comments
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Shawn Davis		Negative	Comments Submitted
6	PPL - Louisville Gas	Linn Oelker		Negative	Third-Party

	and Electric Co.				Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	Third-Party Comments
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	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Negative	Third-Party Comments
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	Third-Party Comments
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Peter Colussy		None	N/A
8	David Kiguel	David Kiguel		Negative	Third-Party Comments
8	Massachusetts Attorney General	Frederick Plett		Abstain	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	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	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		Negative	Comments Submitted

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/33)
Ballot Name: 2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 IN 1 ST
Voting Start Date: 10/30/2015 12:01:00 AM
Voting End Date: 11/9/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 256
Total Ballot Pool: 303
Quorum: 84.49
Weighted Segment Value: 48.01

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	79	1	31	0.5	31	0.5	0	9	8
Segment: 2	10	0.7	2	0.2	5	0.5	0	1	2
Segment: 3	69	1	23	0.469	26	0.531	0	6	14
Segment: 4	21	1	10	0.526	9	0.474	0	0	2
Segment: 5	63	1	26	0.542	22	0.458	0	4	11
Segment: 6	51	1	19	0.487	20	0.513	0	3	9
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	0	0	1	0.1	0	1	0
Segment:	2	0.1	0	0	1	0.1	0	0	1

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9									
Segment: 10	6	0.4	3	0.3	1	0.1	0	2	0
Totals:	303	6.3	114	3.025	116	3.275	0	26	47

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	Ameren - Ameren Services	Eric Scott		Abstain	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		Negative	Third-Party Comments
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A

1	Beaches Energy Services	Don Cuevas		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Negative	Comments Submitted
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	CPS Energy	Glenn Pressler		Negative	Comments Submitted
1	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
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		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		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	Third-Party Comments
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	Martin Boisvert		Affirmative	N/A
1	Iberdrola - Central Maine Power Company	Joe Turano		Abstain	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Negative	Comments Submitted
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Long Island Power Authority	Robert Ganley		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments

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		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
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		Negative	Comments Submitted
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	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	PHI - Potomac Electric Power Co.	David Thorne		Negative	Third-Party Comments
1	Platte River Power Authority	John Collins		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	John Walker		Negative	Comments Submitted

1	PPL Electric Utilities Corporation	Brenda Truhe		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Third-Party Comments
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	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		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	Richard Jackson		None	N/A

	Reclamation				
1	United Illuminating Co.	Jonathan Appelbaum		Negative	Comments Submitted
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
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		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		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	Ameren - Ameren Services	David Jendras		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	Shuye Teng		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A

3	BC Hydro and Power Authority	Pat Harrington		Abstain	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Abstain	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	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
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	Third-Party Comments
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		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		None	N/A
3	Edison International - Southern California	Romel Aquino		None	N/A

	Edison Company				
3	Eversource Energy	Mark Kenny		None	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Grand River Dam Authority	Jeff Wells		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		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Negative	Comments Submitted
3	JEA	Garry Baker		None	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Third-Party Comments
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	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	Third-Party Comments

3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	Comments Submitted
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	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		None	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Negative	Third-Party Comments
3	Platte River Power Authority	Jeff Landis		Negative	Comments Submitted
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Thomas Ward		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Third-Party Comments
3	Puget Sound Energy, Inc.	Andrea Basinski		None	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	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Third-Party Comments
3	Southern Indiana Gas and Electric Co.	Jim Cox		None	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 Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	Westar Energy	Bo Jones		Negative	Comments Submitted
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	Blue Ridge Power Agency	Duane Dahlquist		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	Bill Hughes	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A

4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		None	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
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	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		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public	Stephanie Little		Affirmative	N/A

	Service Co.				
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	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Negative	Comments Submitted
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		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
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	Dominion - Dominion Resources, Inc.	Randi Heise		Negative	Third-Party Comments
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted

5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		None	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Affirmative	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Dixie Wells		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		Negative	Third-Party Comments
5	Nebraska Public	Don Schmit		Negative	Third-Party

	Power District				Comments
5	New York Power Authority	Wayne Sipperly		Negative	Third-Party Comments
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Negative	Comments Submitted
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		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		None	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	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		Negative	Third-Party Comments
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	Affirmative	N/A

5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Third-Party Comments
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	Westar Energy	stephanie johnson		Negative	Comments Submitted
6	AEP - AEP Marketing	Edward P Cox		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		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		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Third-Party Comments
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs Utilities	Shannon Fair		None	N/A

6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Negative	Third-Party Comments
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Earle Saunders		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy		Negative	Third-Party Comments
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	Negative	Third-Party Comments
6	Iberdrola - New York State Electric and Gas Corporation	Julie King		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Third-Party Comments
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments

6	New York Power Authority	Shivaz Chopra		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	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		Negative	Third-Party Comments
6	Omaha Public Power District	Mark Trumble		Negative	Third-Party Comments
6	Platte River Power Authority	Carol Ballantine		Negative	Comments Submitted
6	Portland General Electric Co.	Shawn Davis		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	Third-Party Comments
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	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Negative	Third-Party Comments
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	Third-Party Comments
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		None	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Peter Colussy		None	N/A
8	David Kiguel	David Kiguel		Negative	Third-Party Comments
8	Massachusetts Attorney General	Frederick Plett		Abstain	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	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	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		Negative	Comments Submitted

Previous 1 Next

Showing 1 to 303 of 303 entries

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/33)
Ballot Name: 2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 Non-binding Poll IN 1 NB
Voting Start Date: 10/30/2015 12:01:00 AM
Voting End Date: 11/9/2015 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 220
Total Ballot Pool: 266
Quorum: 82.71
Weighted Segment Value: 54.61

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	65	1	20	0.556	16	0.444	0	21	8
Segment: 2	10	0.5	2	0.2	3	0.3	0	2	3
Segment: 3	62	1	18	0.529	16	0.471	0	15	13
Segment: 4	19	1	8	0.571	6	0.429	0	3	2
Segment: 5	57	1	18	0.6	12	0.4	0	15	12
Segment: 6	43	1	14	0.5	14	0.5	0	8	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0	0	0	0	0	0	2	0
Segment:	2	0.1	0	0	1	0.1	0	0	1

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NERC Balloting Tool (/)

Dashboard (/) Users Ballots Surveys Legacy SBS (https://standards.nerc.net/)

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/33)
Ballot Name: 2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 Non-binding Poll IN 1 NB
Voting Start Date: 10/30/2015 12:01:00 AM
Voting End Date: 11/9/2015 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 220
Total Ballot Pool: 266
Quorum: 82.71
Weighted Segment Value: 54.61

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	65	1	20	0.556	16	0.444	0	21	8
Segment: 2	10	0.5	2	0.2	3	0.3	0	2	3
Segment: 3	62	1	18	0.529	16	0.471	0	15	13
Segment: 4	19	1	8	0.571	6	0.429	0	3	2
Segment: 5	57	1	18	0.6	12	0.4	0	15	12
Segment: 6	43	1	14	0.5	14	0.5	0	8	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0	0	0	0	0	0	2	0
Segment:	2	0.1	0	0	1	0.1	0	0	1

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9									
Segment: 10	6	0.4	3	0.3	1	0.1	0	2	0
Totals:	266	6	83	3.256	69	2.744	0	68	46

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		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		Abstain	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Negative	Comments Submitted
1	Berkshire Hathaway Energy -	Terry Harbour		Negative	Comments Submitted

	MidAmerican Energy Co.				
1	Bonneville Power Administration	Donald Watkins		Abstain	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	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		Negative	Comments Submitted
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		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Abstain	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks,	Payam Farahbakhsh	Oshani	Abstain	N/A

	Inc.		Pathirane		
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		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		None	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	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
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		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Negative	Comments Submitted
1	Northeast Missouri Electric Power	Kevin White		Affirmative	N/A

	Cooperative				
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	John Walker		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	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
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		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Southern Company - Southern Company	Robert A. Schaffeld		Negative	Comments Submitted

	Services, Inc.				
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	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		Negative	Comments Submitted
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
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		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	None	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A

3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		None	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Abstain	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	Comments Submitted
3	City of Leesburg	Chris Adkins		Negative	Comments Submitted
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
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	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		Abstain	N/A

3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Abstain	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		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	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	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		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		None	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Thomas Ward		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	Puget Sound Energy, Inc.	Andrea Basinski		None	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	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		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	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		Negative	Comments Submitted
4	Austin Energy	Tina Garvey		Abstain	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		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 Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		None	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
4	Georgia System	Guy Andrews		Abstain	N/A

	Operations Corporation				
4	Keys Energy Services	Stanley Rzad		Negative	Comments Submitted
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		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	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	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Bonneville Power Administration	Francis Halpin		Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted

5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
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	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		None	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A

5	Kissimmee Utility Authority	Mike Blough		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	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		Negative	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Negative	Comments Submitted
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Alex Chua		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	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy,	Lynda Kupfer		None	N/A

	Inc.				
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	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		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Abstain	N/A
5	Westar Energy	stephanie johnson		Negative	Comments Submitted
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	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	Comments Submitted
6	Bonneville Power Administration	Alex Spain		Abstain	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		None	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	Edison International - Southern California Edison Company	Earle Saunders		None	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy		Negative	Comments Submitted
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	Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A

6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	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		Negative	Comments Submitted
6	Omaha Public Power District	Mark Trumble		Negative	Comments Submitted
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Shawn Davis		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		Abstain	N/A
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	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		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts Attorney General	Frederick Plett		Abstain	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	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	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

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Showing 1 to 266 of 266 entries

9									
Segment: 10	6	0.4	3	0.3	1	0.1	0	2	0
Totals:	266	6	83	3.256	69	2.744	0	68	46

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		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		Abstain	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Negative	Comments Submitted
1	Berkshire Hathaway Energy -	Terry Harbour		Negative	Comments Submitted

	MidAmerican Energy Co.				
1	Bonneville Power Administration	Donald Watkins		Abstain	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	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		Negative	Comments Submitted
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		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Abstain	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks,	Payam Farahbakhsh	Oshani	Abstain	N/A

	Inc.		Pathirane		
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		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		None	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	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
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		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Negative	Comments Submitted
1	Northeast Missouri Electric Power	Kevin White		Affirmative	N/A

	Cooperative				
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	John Walker		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	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
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		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Southern Company - Southern Company	Robert A. Schaffeld		Negative	Comments Submitted

	Services, Inc.				
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	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		Negative	Comments Submitted
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
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		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	None	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A

3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		None	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Abstain	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	Comments Submitted
3	City of Leesburg	Chris Adkins		Negative	Comments Submitted
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
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	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		Abstain	N/A

3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Abstain	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		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	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	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		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		None	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Thomas Ward		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	Puget Sound Energy, Inc.	Andrea Basinski		None	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	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		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	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		Negative	Comments Submitted
4	Austin Energy	Tina Garvey		Abstain	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		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 Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		None	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
4	Georgia System	Guy Andrews		Abstain	N/A

	Operations Corporation				
4	Keys Energy Services	Stanley Rzad		Negative	Comments Submitted
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		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	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	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Bonneville Power Administration	Francis Halpin		Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted

5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
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	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		None	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A

5	Kissimmee Utility Authority	Mike Blough		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	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		Negative	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Negative	Comments Submitted
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Alex Chua		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	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy,	Lynda Kupfer		None	N/A

	Inc.				
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	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		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Abstain	N/A
5	Westar Energy	stephanie johnson		Negative	Comments Submitted
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	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	Comments Submitted
6	Bonneville Power Administration	Alex Spain		Abstain	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		None	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	Edison International - Southern California Edison Company	Earle Saunders		None	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy		Negative	Comments Submitted
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	Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A

6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	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		Negative	Comments Submitted
6	Omaha Public Power District	Mark Trumble		Negative	Comments Submitted
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Shawn Davis		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		Abstain	N/A
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	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		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts Attorney General	Frederick Plett		Abstain	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	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	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

Showing 1 to 266 of 266 entries

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/33)
Ballot Name: 2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 Non-binding Poll IN 1 NB
Voting Start Date: 10/30/2015 12:01:00 AM
Voting End Date: 11/9/2015 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 230
Total Ballot Pool: 274
Quorum: 83.94
Weighted Segment Value: 56.25

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	69	1	24	0.558	19	0.442	0	18	8
Segment: 2	10	0.5	2	0.2	3	0.3	0	2	3
Segment: 3	64	1	21	0.568	16	0.432	0	14	13
Segment: 4	19	1	9	0.563	7	0.438	0	1	2
Segment: 5	57	1	22	0.595	15	0.405	0	9	11
Segment: 6	45	1	18	0.545	15	0.455	0	6	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0	0	0	0	0	0	2	0
Segment:	2	0.1	0	0	1	0.1	0	0	1

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9									
Segment: 10	6	0.4	3	0.3	1	0.1	0	2	0
Totals:	274	6	99	3.328	77	2.672	0	54	44

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		Abstain	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	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
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		Negative	Comments Submitted
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	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		Negative	Comments Submitted
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		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	Comments Submitted
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	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	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		None	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	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
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		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public	Charles Raney		Negative	Comments Submitted

	Service Co.				
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	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Negative	Comments Submitted
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	John Walker		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	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Comments Submitted
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	SCANA - South	Tom Hanzlik		Abstain	N/A

	Carolina Electric and Gas Co.				
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
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		Abstain	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		Negative	Comments Submitted
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
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		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	None	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System	Gregory Campoli		None	N/A

	Operator				
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		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	Shuye Teng		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
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	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Abstain	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	Comments Submitted
3	City of Leesburg	Chris Adkins		Negative	Comments Submitted
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
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	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		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Grand River Dam Authority	Jeff Wells		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		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	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	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		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		None	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Thomas Ward		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public	Jeffrey Mueller		Abstain	N/A

	Service Electric and Gas Co.				
3	Puget Sound Energy, Inc.	Andrea Basinski		None	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	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		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	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		Negative	Comments Submitted
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Negative	Comments Submitted
4	City of New Smyrna Beach Utilities	Tim Beyrle		Negative	Comments Submitted

	Commission				
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		None	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Keys Energy Services	Stanley Rzad		Negative	Comments Submitted
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		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	AEP	Thomas Foltz		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	Matthew Pacobit		None	N/A

	Cooperative, Inc.				
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
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		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	Dominion - Dominion Resources, Inc.	Randi Heise		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	Edison International - Southern California	Thomas Rafferty		None	N/A

	Edison Company				
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		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	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		Negative	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Negative	Comments Submitted
5	NextEra Energy	Allen Schriver		Affirmative	N/A

5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Alex Chua		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	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	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		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Abstain	N/A
5	Tri-State G and T	Mark Stein		Abstain	N/A

	Association, Inc.				
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Abstain	N/A
5	Westar Energy	stephanie johnson		Negative	Comments Submitted
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		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		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		None	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	Edison International - Southern California Edison Company	Earle Saunders		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted

6	Florida Municipal Power Pool	Tom Reedy		Negative	Comments Submitted
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	Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	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		Negative	Comments Submitted
6	Omaha Public Power District	Mark Trumble		Negative	Comments Submitted
6	Platte River Power Authority	Carol Ballantine		Negative	Comments Submitted
6	Portland General Electric Co.	Shawn Davis		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		Abstain	N/A
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	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		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts Attorney General	Frederick Plett		Abstain	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	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	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

Showing 1 to 274 of 274 entries

Previous 1 Next

Survey Report

Survey Details

Name 2009-02 Real-time Monitoring and Analysis Capabilities | IRO-018-1 & TOP-010-1

Description

Start Date 9/24/2015

End Date 11/9/2015

Associated Ballots

2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 IN 1 ST

2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 Non-binding Poll IN 1 NB

2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 IN 1 ST

2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 Non-binding Poll IN 1 NB

Survey Questions

1. The SDT has proposed a new standard IRO-018-1 to address RC monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

Yes

No

2. The SDT has proposed a new standard TOP-010-1 to address TOP and BA monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

Yes

No

3. Do you agree with the Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

Yes

No

4. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

Yes

No

5. Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.

Responses By Question

1. The SDT has proposed a new standard IRO-018-1 to address RC monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

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

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

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

Our comments on the SAR posting essentially disagreed with the creation of this standard and the TOP-010 standard to mandate monitoring and analysis capability for the RC and TOP, which are the fundamental "bread and butter" capabilities that these entities must have to perform their assigned functions. We further suggested that the FERC directive could be met by an alternative but more appropriate means of incorporating the necessary requirements in the Organization Certification Requirements.

The SDT disagree with our proposal citing that: "…. these capabilities should be demonstrated at the organization certification stage, but believes they should also be maintained on an ongoing basis through adherence to standards. Furthermore, development of standards is appropriate since, in general, organization certifications are based on the body of approved standards."

We continue to respectfully disagree that "maintained on an ongoing basis through adherence to standards" is the only approach. Such maintenance can also be mandated through the certification process. For example, if basic monitoring capability is required for certification, there needs to be periodic assessment of whether or not such capability continues to exist at a level to be specified, or no lower than that assessed at the initial certification stage. To argue that the only way to ensure maintenance through adherence to standards, then a good part of the current

certification requirements will have to become standards or whose quality or functional capability need to be ascertained through standards. This is not the case today, nor do we think this is the case in the future.

We once again urge the standard drafting team to consider the organization certification alternative as a means to address this FERC directive. For so long as the directive is met, it should not matter whether the requirements are incorporated into the certification requirements or in a new standard. Putting them into certification requirement is consistent with the intended use of organization certification process to ensure the responsible entities have the capability to fulfill their functional obligations; whereas putting them into reliability standards is inconsistent with the intended use of standards to drive the right planning and operation behaviors.

Notwithstanding the above disagreement with creating this and the TOP-010 standards, the currently posted draft standard appears to be micro-managing the requirements and process for providing adequate tool/capability.

The 5 requirements in the proposed IRO—018 standard essentially require that the RC:

· Implement an Operating Process or Operating Procedure to address the quality of the Real-time data;

· Indicate to the operating personnel the quality of the Real-time data

· Implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments

· Provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments

· Utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

These requirements mandate the “how”, not the “what”, and are overly prescriptive and micro-managing the daily business of the RC. If the SDT

decides to keep using a standard to meet the FERC directive, then the standard needs only to be one requirement that mandates the RC having in place acceptable quality monitoring and analysis capability at all times (except the down time for repair but for which a backup needs to be in place) for the RC to perform its functions and meet all applicable reliability standard. This requirement will be the "what", i.e., the necessary capability to perform the RC functions with specific reliability outcome - to ensure reliability.

In brief, we are unable to support this standard for two main reasons: (a) that the standard is more suited for inclusion in the Organization Certification Requirements and (b) the standard as currently drafted is overly prescriptive and micro-managing.

Document Name:

Likes: 0

Dislikes: 0

Tyson Archie - Platte River Power Authority - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer: No

Answer Comment:

We would like to see "quality" defined or clarrified. Also, we are not sure who is responsible for the quality of the data received from the interconnections. We also support some of the comments coming out of the MRO standards group.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: No

Answer Comment:

The NSRF has concerns with redundancy and technical complications with the IRO-018-1 standard as proposed. The data quality objective can be simplified into a single requirement IRO-018-1 or TOP-001-3 / IRO-008 which is for entities to have tools or processes that consider data quality to reasonably assure a reasonably high confidence that the system is in a reliable state. Existing Energy Management Systems (EMS) / Real-Time Contingency Analysis (RTCA) tools already have this capability.

Redundancy:

The NSRF recognizes that FERC directed the drafting team to address missing data quality issues based on the 2003 blackout report. However, existing standards TOP-001-3 and TOP-003-3 already require effective monitoring and control which includes proper data.

As an example, R13 of TOP-001-3 sets clear requirements that a real-time assessment must be performed at least once every 30 minutes.

All TOPs assessment tools already consider bad data detection and identification from embedded software algorithms which are pre-requisites for successful execution of SE/RTCA. TOP's engaged in monitoring the execution of their assessment tool(s) already address problems with data input quality and assessment quality.

Assessment tools must have robust data quality input and assessment capabilities to detect and identify problem(s) with any single piece of data (out of thousands of inputs) especially if that particular bad input (or limited set of bad input data) did NOT affect overall successful performance of the tool.

Technical Compliance Complications that Distort the Reliability Goal:

The zero defect nature of compliance, until fixed, drives unnecessary costly EMS / RTCA system upgrades without measureable system reliability improvements. The proposed TOP-010 and IRO-018 standards introduce vague and unclear formulations that will cause misunderstandings during compliance audits. Therefore, it is better to revise TOP-010 to a single requirement or revise TOP-001-3 or TOP-003-3 (and the corresponding IRO standards) with an additional simple requirement for entities to have tools or processes that considers data quality to reasonably assure a high confidence that the system is in a reliable state.

Assessment tools use thousands of input data points including analog measurements and switching device statuses. Therefore, the reliability goal(s) are that the assessment tool has bad data detection and identification algorithms that allow the assessment tool to solve, and notify / log the system operator of bad data, and alarm if the bad data may compromise the assessment or solution.

Identifying vague input data issues such as “analog data not updated” or “data identified as suspect” is problematic from a compliance standpoint. Some Energy management Systems (EMS) simply do cannot identify all suspect data and therefore the zero defect compliance expectation to identify all suspect data or all bad analog data is technically infeasible. The reliability goal is a high confidence assessment that the system is in a reliable state. That is very different from the stated compliance zero defect standard as written to identify all “analog data not updated” or identify “all suspect data”.

Significant technical problems exist with the TOP-010 requirements when applied to input data received from other TOPs or RC's (either directly or via ICCP). There are no technically feasible mechanisms to detect for “manually entered statuses. An example is detecting a manually entered “CLOSED” circuit breaker status whose actual status is “OPEN”, if such data was received via ICCP.

TOP-010 R3 is unclearly defined as Transmission Operators would have major difficulty in coming up with a conclusion as to what is “the quality of data necessary to perform real-time assessment”. At any moment in time, any specific measurement (or subset of measurements) might either be lost or be detected as “bad”. That does not necessarily mean that the real-time assessment would be inaccurate or invalid. The tool’s accuracy can be measured by other inherent quantitative indicators such as algebraic sum of allocation errors” or “confidence percentile”. An aggregate reasonable confidence percentile measurement would be a sufficient system reliability objective reasonably proving the system was in a reliable state.

TOP-010 R5 introduces unclear terminology of “maintaining the quality of any analysis used in real-time assessment”.

Document Name:

Likes: 1 Grand River Dam Authority, 3, Wells Jeff

Dislikes: 1 Porter Tammy On Behalf of: Rod Kinard, Oncor Electric Delivery, 1,

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer: No

Answer Comment:

RC, BA & TOP entities currently have adequate tools for real-time monitoring and analysis. The existing Standards adequately define what needs to be monitored by each entity without defining the tools. Creating new requirements will not increase the reliability of the BES.

Additionally, some of the new proposed requirements (IRO-018-1 Req. 1, TOP-010-1 Req. 1) state:

Each RC/TOP/BA shall implement and Operating Process to address the *quality* of the Real-time data… the term *quality* is ambiguous and subjective. This term needs to be defined. Similar to Requirement 2, the terms *indications of quality* needs to be defined. If not defined, it could result in varying interpretations throughout the industry.

Lastly, the NERC Operating Reliability Subcommittee (ORS) has drafted a Reliability Guideline, "Loss of Real-Time Reliability Tools Capability / Loss of Equipment Significantly Affecting ICCP Data." This guideline will help ensure that tools are adequate and if they are degraded for any reason, the potentially impacted entities are aware and can take action if needed.

PJM supports the comments submitted by the ISO/RTO Council Standards Review Committee.

Document Name:

Likes: 5

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Long Island Power Authority, 1, Ganley Robert
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer: No

Answer Comment:

R1.1 uses “but not limited to”. That language is too open ended and cannot be audited or compliance limited. Compare it to R3. ‘ But not Limited to” only belongs in a Measurement.

R2 is a ambiguous in whether a single data point of bad quality needs to be flagged or if the aggregate data is so bad that state estimator can’t solve. Modern EMS systems incorporate data quality checks within their algorithms. However, how this requirement is phrased will dramatically impact the compliance risk an organization faces.

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Darnez Gresham On Behalf of: Thomas Mielnik, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3

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

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: No

Answer Comment:

R3 & R4: Duke Energy requests further clarification on the compliance aspects of R3 and R4. Operating studies use the latest information available, but that data changes continuously so the studies will never be 100% accurate. More information is necessary to know how to measure their quality effectively.

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
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
Mark Schultz	City of Green Cove Springs	FRCC	3
Chris Adkins	City of Leesburg	FRCC	3
Ginny Beigel	City of Vero Beach	FRCC	9

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer: No

Answer Comment:

In part 1.1 of R1, if the bulleted list is intended to be an example list, then the examples should not be given part numbers but should be rolled up into the main sentence. If it is intended to be a minimum set of criteria, then “but not limited to” should be replaced with “at a minimum”.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1 -

Selected Answer: No

Answer Comment:

See comments for Q2.

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:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

While Peak supports the spirit of this proposed Standard, Peak recommends there be a requirement for entities who provide data per IRO-010 to resolve data quality issues in a mutually agreeable time schedule. The RC could have a process, but if there is no requirement for entities to fix the issues the end result is not achieved. The Standard as written falls short of providing resolution. The same comments apply to TOP-010-1.

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - PPL NERC Registered Affiliates - 1,3,5,6 - SERC,RFC

Group Information

Group Name: PPL NERC Registered Affiliates

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E and KU Energy, LLC	SERC	1,3,5,6
Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
Dan Wilson	LG&E and KU Energy, LLC	SERC	5
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
PPL NERC Registered Affiliates	SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas McElhinney - JEA - 1,3,5 - FRCC

Group Information

Group Name: JEA

Group Member Name	Entity	Region	Segments
Ted Hobson	JEA	FRCC	1
Garry Baker	JEA	FRCC	3
John Babik	JEA	FRCC	5

Voter Information

Voter	Segment
Thomas McElhinney	1,3,5
Entity	**Region(s)**
JEA	FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SERC,SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
John Allen	City Utilities Springfield Missouri	SPP	1,4
Darryl Boggess	Western Farmers Electric Cooperative	SPP	1,5

Donald Hargrove	Oklahoma Gas and Electric	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Robert Hirchak	CLECO	SPP	1,3,5,6
J. Scott Williams	City Utilities of Springfield Missouri	SPP	1,4
Sing Tay	Oklahom Gas and Electric	SPP	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5
Kyle McMenamin	Xcel Energy	SPP	1,3,5,6

Voter Information

Voter	**Segment**
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	MRO,WECC,SERC,SPP

Selected Answer: No

Answer Comment:

We do not believe the issues addressed by the FERC directive rise to the level of requiring a reliability standard. The intent of the directive and the resulting actions to be taken by the various entities would be better served by an official Guideline rather than a generic standard. Forcing this into a Standard requires a one-size fits all approach that is leading to varied interpretations on “quality” and “adequacy” and may not enhance reliability of the BES.

We believe the requirements in general could be improved to be more results based. As written, they largely will only result in identifying deficiencies after the fact when doing event analysis. An entity may have a process or procedure as required, but they could miss a piece of data or fail to identify fully the impact a quality issue may have upon their situational awareness. Simply having the process does not result in increased reliability.

Most entities already have a process in place to alarm or indicate data quality as needed to maintain reliability. Entities are already required to operate reliably, within SOLs and IROLs, etc. The creation of this standard as written would serve only to document that process and put it under auditable enforcement – with no discernible impact to maintaining reliability. In order to make this standard truly results based, there needs to be some identification of the quality level, or data quality thresholds that must be maintained in order for reliability to be maintained. Then that level (or quality of the data measurements) must be maintained per the standard.

We suggest that there needs to be more direction given by the Standard in a few areas. One is that the applicable entity should be determining a data range, time periods, number of manually entered values, etc. that can degrade analysis to the point reliability is threatened (R1.1.1-R1.1.4).

We also find it problematic when an entity may not "own" the data and is simply receiving a quality flag from a sender. The RC for example may not receive an accurate quality flag or the quality flag is corrupted in translation over ICCP. Also, there is no requirement that the measurement devices even be of a particular accuracy. For example the quality threshold may be more narrow than the accuracy of the device.

The use of the term "suspect" in R2.1.4 in TOP-010-1 could lead to an interpretation that the operator "should have suspected" the data was incorrect. The word "suspect" is used in some EMS packages as an identifier for garbage or data that is suspect. We recommend the word be evaluated and replaced.

R3 is very problematic in that it infers there is a level of in-adequacy that studies must not fall below when requiring a level of "quality" to be maintained. This seems to be an attempt to not use the word "adequate". Without defining the required level of quality, there is no way an entity can be compliant. Any entity may experience some reduced level of quality, but may still have acceptable performance from their studies without taking action to correct or mitigate the data. As written, the entity would be in violation for simply failing to "maintain" the level of quality. Perhaps R3 could be written this way:

R3. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to maintain an acceptable level of quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

3.1. Criteria for determining the minimum quality of any analysis used in its Real-time Assessments; and

3.2. Actions to resolve unacceptable quality deficiencies in any analysis used in its Real-time Assessments.

R4 seems to be applicable to situations where a tool is used to perform the RTA. This can become problematic when the assessment is simply an evaluation done by reviewing data and determining that no changes on the system have occurred such as could occur with a TOP who has only a few BES elements and does not possess an EMS or RTCA style "tool".

We suggest that altering the phrase "independent alarm process monitor" could be beneficial. As stated, the phrasing seems to suggest particular processes or tools rather than the intent to just have an "independent process" to monitor the alarming system. We suggest the change as:

R5. Each Reliability Coordinator shall utilize a process to independently monitor its Real-time monitoring alarm process monitor in order to provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The SRC fails to see the reliability risk that this project is intending to address. The August 14 Blackout as well as the 2011 Southwest Outage have thoroughly and exhaustively investigated, reported upon, and the root causes mitigated appropriately. Therefore, pointing to the need for this project based on mitigated, historical events falls short of identifying the reliability risk that this is intended to "fix." If, for example, WECC continues to have a vested interest in further mitigating the 2011 Southwest Outage though standard development, we suggest this project be migrated into a regional standard for WECC. Lastly, the SRC believes that, absent a Standard specific for tools, a RC, TOP, or BA would, in fact, have violations of existing operational Requirements if they do not provide adequate monitoring and tools to their operators (i.e. other "things" would happen).

Further, the Requirements as written, "…to address the quality of the Real-time data necessary…" are ambiguous, lack consensus about how to measure, and do not rise to the level of a NERC Standard.

This proposed project appears to be well-suited for a guideline document as opposed to a Standard. As written, the SAR appears to intend to write a "how" not "what" Standard (*i.e.*, it does not appear to be a results-based standard). The SRC believes that the existing Standards (*i.e.*, IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (*i.e.*, without defining the "how"), which is appropriate. In the alternative, this could be considered a process to be used for Certifying new entities, in line with a methodology developed by the ERO and registered entities for assessing adequacy of tools for addressing the "quality" of real-time data, for assurance that RC, BA and TOPs have the ability to monitor appropriately in accordance with existing, performance-based Standards Requirements.

The SRC notes that the tools available to operators have progressed well beyond those available in 2003. If defined tools would have been hardcoded in a standard at that time, it would have limited focus and investment to those things that were in the standard. Further, expanding on our point above, the SRC believes that the "what" regarding tools is more appropriately captured in the certification expectations for BAs, RCs, and TOPs. Additionally, it would be appropriate for Regions to evaluate tools as part of the Registered Entity's Inherent Risk Assessment (IRA). This would include the scope of tools, backups, etc. and would provide an adaptable approach that would encourage continuous improvement.

Additionally, the SRC recommends that NERC coordinate with the NATF to encourage inclusion of an ongoing "care and feeding" of tools evaluation and information sharing in their efforts with the provision that they make information on good practices available to the wider NERC community so that non-members can learn from the innovation of others.

Finally, to avoid these issues in the future and to support communicating to FERC when a Standard is not needed and another tool is more suitable, the SRC suggests that future SARs be voted on by industry to determine whether they should proceed as a Standards project or another means is a more appropriate method through which to achieve the SAR's objective.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Not applicable tp BPA

Document Name:

Likes: 0

Dislikes: 0

Jack Stamper - Clark Public Utilities - 3 -

Selected Answer: No

Answer Comment:

See comments in item 2 below.

Document Name:

Likes: 0

Dislikes: 0

Megan Wagner - Westar Energy - 6 -

Selected Answer: No

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: Project 2009-02

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Michael Forte	Con Edison	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
Kelly Dash	Con Edison	NPCC	3
Michael Jones	National Grid	NPCC	3
David Burke	Orange and Rockland Utilities	NPCC	3
Peter Yost	Con Edison	NPCC	4
Wayne Sipperly	New York Power Authority	NPCC	4

Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7

Voter Information

Voter

Ruida Shu

Segment

1,2,3,4,5,6,7

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer: No

Answer Comment:

By Part 1.1 stating “Criteria for evaluating potential Real-time data quality discrepancies…” implies that a contingency analysis has to be done. Suggest removing “potential” from Part 1.1.

Language in R1.1 uses “but not limited to”. That language is too open ended and cannot be audited. Compare it to R3 use of “shall include”. “But not limited to” only belongs in a Measurement.

R2 is a bit ambiguous in whether a single data point of bad quality needs to be flagged or if the aggregate data is so bad that the state estimator can’t solve.

Suggest replacing the word “any” from R3 and R4 (relative to “any analysis”) and replacing with “reliability related” as “any” could be too broadly applied or interpreted. Additionally, the term analysis is broad. Standards related to Project 2014-03, approved through NERC as of this time, define such things as Real Time Assessments and Operational Planning Analysis. It's not exactly clear what analysis would be referring to.

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer: No

Answer Comment:

Need more clarity in general; see Q2 for more specifics.

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5

Voter Information

Voter	Segment

Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer: No

Answer Comment:

(1) The language within Requirement R1 is vague and should not require criteria for evaluating data quality. References to criteria for evaluating data quality should not be ambiguous and unenforceable. The requirement needs to identify what real-time data is necessary to perform monitoring and assessments and consider if the data specifications maintained for reliability. The SDT should also clarify what is considered “quality” data and how an entity should identify data quality. The minimum criteria is not specific and does not provide enough information to make an objective determination.

(2) Requirement R4 provides indications that the drafting team expects System Operators to receive quality data. If an entity makes data available with a quality code, but the system fails to update the quality code, is this a violation? The SDT also needs to identify the evidence required for this requirement and if a validation process is necessary.

(3) The language within Requirement R5 expects an entity to have redundant alarms or independent alarms for real-time monitoring. What does “independent” mean in this context? The drafting team provides technical examples such as “heartbeat” or “watchdog” monitoring systems in its rationale, but does the independent system need to be separate from the real-time monitoring?

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

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer: No

Answer Comment:

ReliabilityFirst offers the following comments for consideration:

1. **Requirement R2**

    i. **It is unclear as to what the phrase "indication(s) of the quality of the Real-time data" is referring to. RF requests clarification on the term "indications" and what this involves.**

    i. **Also, since the System Operators work for the RC, it is unclear whom at the RC will be providing "indications" to the System Operators. As written, the System Operators (working for the RC) could provide indications to themselves. This does not seem to be the intent of the Requirement.**

2. **Requirement R4**

    i. **Similar to Requirement R1, it is unclear as to what the phrase "indication(s) of the quality of any analysis" is referring to. RF requests clarification on the term "indications" and what this involves.**

    i. **Also, since the System Operators work for the RC, it is unclear whom at the RC will be providing "indications" to the System Operators. As written, the System Operators (working for the RC) could provide indications to themselves. This does not seem to be the intent of the Requirement.**

Document Name:

Likes: 0

Dislikes: 0

Selected Answer: No

Answer Comment:

Comments: ERCOT expresses its concern that the proposed standard is too prescriptive and goes beyond the associated FERC directive regarding a requirement addressing “capabilities.” In particular, these standards were developed to address operator awareness of tool or other outages that could impact real-time monitoring. Further, several of the requirements involve many more entities than the Reliability Coordinators and, absent a requirement for coordination, participation, and action in response to the Reliability Coordinator when an issue is identified, the proposed standard will not achieve its intended objective as written. This is extremely challenging (R1.2) because the majority of issues related to poor data quality or invalid analysis tool solutions can only be resolved by parties outside of the Reliability Coordinator (e.g facility owners, telecom companies, etc.) Additionally, real-time data and monitoring capabilities are critical to the certification of a Reliability Coordinator and are not “dynamic.” Because such “capabilities” are complex, require coordination and inputs from other entities, and are key to the continued performance of a Reliability Coordinator’s duties, they are not subject to change or revision often and, therefore, likely do not need continued monitoring and assessment. Finally, several other reliability standards and associated requirements are contingent upon the availability of real-time tools and data, which standards and requirements are subject to the compliance monitoring and enforcement program. Thus, ERCOT would recommend that requirements addressing capabilities be utilized during certification and not as a reliability standard subject to the compliance monitoring and enforcement program.

Should NERC continue this project, however, ERCOT recommends that they are narrowly focused on alerting and alarming operators when their tools and/or displays are no longer working or otherwise compromised during real-time operations. Accordingly, ERCOT provides the following comments by requirement:

Requirements R1 and R2

ERCOT respectfully recommends that requirements R1 and R2 be combined. Because the need to address data issues generally arises as a result of a data indicator or the need for manual data intervention by system operators, the value of a process to address such issues without the context of time or need is significantly diminished. Hence, ERCOT proposes the following:

R1. Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R1.1 The Reliability Coordinator shall initiate actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data when failure or degradation is indicated.

Although this change does not accomplish the intended objective since the parties required to respond to the RC's actions initiated to coordinate resolution do not have any requirements to respond or correct the issue, it does however limit the requirements to what the RC as an entity has control over.

Requirements R3 and R4

ERCOT respectfully recommends that requirements R3 and R4 be combined. Because the need to address issues with real-time analyses generally arises as a result of an indicator that a particular analysis did not complete, is offline, or there is a need for manual intervention by system operators, the value of a process to address such issues without the context of time or need is significantly diminished. Additionally, the availability of back up or offline processes for real-time analyses mitigates the risks associated with an issue or outage of analysis capabilities. For R4, specifically "quality" is more ambiguous when considering analysis tools vs data quality. Data quality is more discrete defined by predetermined limits for analog values and logic behind discrete/binary values. Analysis "quality" is not an appropriate term as it infers a range rather than a discrete nature (valid/invalid).Hence, ERCOT proposes the following:

R3. Each Reliability Coordinator shall provide its System Operators with indication (s) of the tool(s) used in its Real-time monitoring and Real-time Assessments are functioning as intended. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R3.1 The Reliability Coordinator shall initiate actions to resolve any issues internally and to coordinate resolution of any data issues that are impacting such tool(s) with entity(ies) responsible for providing data inputs to such tool(s) when failure or degradation is indicated.

ERCOT recommends that necessary revisions be made to the Violation Severity Levels to ensure consistency with the proposed revisions.

Document Name: Unofficial_Comment_Form_2009-02__ercot_final.docx

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

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:

Answer Comment: Neutral position as it does not applies to ITC

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE recommends making the retention period for R3 longer than 30 days. This requirement consists of a procedure and the implementation of a procedure. A 30 day retention policy will make it very difficult for a registered entity to demonstrate compliance. The policy implies that there is not a reliability issue if compliance monitoring is not performed within 30 days (or every 30 days). Is there an event analysis category that captures quality of data and assessments where the CEA may call for longer retention? Effectively this retention policy is indicative of masking a reliability issue where the quality of the data used in assessments and the quality indication to the System Operators may be inadequate to perform the reliability functions and the only indication of a failure will occur during an event (or the preceding 30 days of a monitoring activity).

Texas RE suggests making IRO-018-1 R3, R4 clearer by using some of the language from the rationale. The requirements address "quality of analysis", which could depend on many factors, while the rationale uses the language "to address issues related to the quality of the analysis inputs used for Real-time Assessments".

Texas RE recommends revising the phrase "with indication(s) of" used in proposed IRO-18-001, R2 and R4 as it is vague. Presumably, the purpose of IRO-18-001, R2 and R4 appears to be to ensure that the results of the required evaluations of potential Real-time data quality discrepancies are communicated to System Operators so they can be incorporated into Real-time monitoring and Real-time assessments. Accordingly, Registered Entities should be required to provide appropriate information from their data quality assessments to their System Operators. Texas RE suggests substituting "relevant information and/or analyses concerning" for "with indication(s) of" to require appropriate, relevant information and/or any analyses of the quality of Real-time data be communicated to System Operators, not merely indications of data quality.

The reference to "with indications of" in the corresponding measures should also be revised along these lines. However, the types of evidence identified in the measures satisfy the proposed "relevant information and/or analyses concerning" standard.

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery,1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Marsha Morgan

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

SERC

Selected Answer: No

Answer Comment:

Southern believes that the criteria in R1.1 should be limited to the RC’s ability to monitor and assess the current/expected condition of its RC area within the capabilities of its monitoring tools not including the criteria listed in R1.1.1-R1.1.4.

Each RC has the inherent responsibility to protect the integrity of the system in its RC area and contribute to the overall integrity of Interconnection. In order to fulfill this responsibility, the RC performs monitoring through the information collected from the modeled facilities in its RC area to accurately assess the state of the system and to perform real time assessments. Throughout this process, the RC is constantly evaluating the quality of data received to ensure it has an accurate state of system conditions to perform real time assessments. To impose a new standard focusing on data quality would only serve as administrative in nature and would not provide any substantial increases in reliability.

Document Name:

Likes: 0

Dislikes: 0

2. The SDT has proposed a new standard TOP-010-1 to address TOP and BA monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

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

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

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

Clarity is needed regarding how granular the Requirements are to the data points themselves. For example, is the Transmission Operator obligated in R3 to provide indication(s) of quality on a data point basis, or rather, may it be done as a collection of data points, grouping them as needed? Of even greater concern, would the “actions to coordinate resolution” in R1 need to be performed on a per-data point basis as well? Hundreds of thousands of data points are involved in Real-time monitoring and Real-time Assessments, and the requirements in this standard must be written realistically to accommodate a high volume of data points which continue to increase.

In addition, AEP has a large volume of data provided by external entities. AEP would have little to no ability to “coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data” as specified in R1.2, for this externally provided data.

Perhaps a re-ordering of the TOP-10-1 requirements could help the overall flow of the standard. For example, it may be preferable to have a Requirement for indications of quality (R3 for example) to precede a Requirement to have an Operating Process or Operating Procedure to address the quality of that data (R1 for example).

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

We do not agree with the need to create this standard, and the way the proposed standard is drafted (overly prescriptive and micro-managing). Please see our comments under Q1.

Document Name:

Likes: 0

Dislikes: 0

Tyson Archie - Platte River Power Authority - 5 -

Selected Answer: No

Answer Comment:

Platte River (PRPA) like many smaller TOP's does not have an EMS system capable of performing Real-Time Assessments. To accomplish this task, we contract our Reliability Coordinator to run our Real-Time Assessments. Platte River provides data points to the RC, who runs the Real-Time Analyses and then provides PRPA with the advanced applications.

PRPA does not have a concern with the intent of the standard, but requests that the drafting team address the possibility of relying on 3rd party contracts to perform Real-Time Assessments for entities that do not possess the ability to perform each of the requirements in this standard.

Without the ability to contract a 3rd party for these services, the financial burden of purchasing and installing a new EMS system capable of performing these tasks would easily reach into the millions of dollars.

Document Name:

Likes: 0

Dislikes: 0

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer: No

Answer Comment:

We would like to see "quality" defined or clarrified. Also, we are not sure who is responsible for the quality of the data received from the interconnections. We also support some of the comments coming out of the MRO standards group.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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:

R1 and R2:

It can be very difficult to identify some of the real-time data quality problems listed in this Standard, particularly analog data that is not updating. Many current systems do not have the capability to easily detect this for all analogs, and adding this capability for all data points could require extensive Software, database, and/or Hardware (for performance reasons) changes that cannot be easily or quickly implemented.

As real-time telemetry becomes more de-centralized in the field and as we are required to rely more and more on data from other entities (via ICCP), it becomes more and more difficult to detect data that is out of range. Putting this requirement on an entity that has no control over the source of the data or how it is provided seems to put an unfair regulatory burden on that entity.

Most of the real-time data quality criteria seem focused on analog data, but incorrect digital data can have a greater impact on analysis results than incorrect/stale analog data. However, identifying non-updating digital data can be even more difficult than identifying non-updating analog data.

How do we prove to an auditor that we identified all instances of data with poor quality?

These requirements seemed focused on evaluating the quality of incoming real-time data. Are there any requirements for providing accurate quality codes with data? For example:

Both ICCP and some RTU protocols support including quality codes with data values. For example, if an entity receiving ICCP data relies on these quality codes to at least partially determine the quality of a data point, then the received quality codes need to be accurate.

Both ICCP and some RTU protocols support including time-stamps of the most recent change of a data point value. Some systems use this received time-stamp when processing the data, and it can impact applications used by operators, including where a new alarm for that point appears in an EMS/SCADA alarm list. Receiving an incorrect time-stamp can negatively impact the information and results provided to an operator.

R3 and R4:

What is considered sufficient notification to an operator of real-time data quality problems? If quality codes are shown on EMS/SCADA displays, an operator may not look at the displays with data quality issues. But if alarms are generated to notify the operator, the increase in alarm volume may detract the operator's attention from more important alarms.

Summarizing the quality of thousands of real-time measurements for an operator may not be something existing systems can easily do. This may require software and possibly hardware additions to an EMS/SCADA.

R5: There is no guidance provided for a Transmission Operator to create criteria to evaluate the quality of analysis used in its Real-time Assessments. If an auditor will be expected to review the criteria used by a Transmission Operator, the guidelines that will be provided to auditors for this purpose should be listed here.

R7: With current EMS/SCADA architectures, it can be difficult to define what comprises the "alarm processor". While requirements R1-R4 of this Standard may cover the quality of the telemetered inputs to the EMS/SCADA, there are many EMS/SCADA components used after that to make operators aware of alarms. It is not just a specific alarm processing program, but also includes things such as the EMS/SCADA data dissemination programs, the EMS/SCADA User Interface application, audible alarming capabilities, even the operator console hardware itself. Should this requirement be re-worded to make it clearly cover the ability of the system to make alarms available to operators and not imply it is limited it to a specific “program”?

VSLs:

R3 & R4: It is not clear from the wording of the single VSL level (which is Severe) if a violation of this Standard is incurred only if there are NO indications of quality of real-time data. If the meaning is to include situations where one or a few points with bad quality are missed (i.e., not notified to an operator) than assigning a Severe VSL seems inappropriate, and several levels of violations should be implemented.

R6: Is it correct that a violation of this Standard is incurred only if there are NO indications provided to operators of poor quality of analysis results, and that missing some number of these instances is not a violation of this Standard? If the intent is to consider even a single miss a violation then assigning it a Severe VSL seems inappropriate, and several levels of violations should be implemented.

R7: Is it correct that occasional failures of the independent alarm process monitor are not violations of this Standard?

Document Name:

Likes: 0

Dislikes: 0

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer: No

Answer Comment:

RC, BA & TOP entities currently have adequate tools for real-time monitoring and analysis. The existing Standards adequately define what needs to be monitored by each entity without defining the tools. Creating new requirements will not increase the reliability of the BES.

Additionally, some of the new proposed requirements (IRO-018-1 Req. 1, TOP-010-1 Req. 1) state:

Each RC/TOP/BA shall implement and Operating Process to address the *quality* of the Real-time data… the term *quality* is ambiguous and subjective. This term needs to be defined. Similar to Requirement 2, the terms *indications of quality* needs to be defined. If not defined, it could result in varying interpretations throughout the industry.

Lastly, the NERC Operating Reliability Subcommittee (ORS) has drafted a Reliability Guideline, "Loss of Real-Time Reliability Tools Capability / Loss of Equipment Significantly Affecting ICCP Data." This guideline will help ensure that tools are adequate and if they are degraded for any reason, the potentially impacted entities are aware and can take action if needed.

PJM supports the comments submitted by the ISO/RTO Council Standards Review Committee.

Document Name:

Likes: 5

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Long Island Power Authority, 1, Ganley Robert
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer: No

Answer Comment:

R1.1 uses “but not limited to”. That language is too open ended and cannot be audited or compliance limited. Compare it to R3. ‘ But not Limited to” only belongs in a Measurement.

R2 is ambiguous in whether a single data point of bad quality needs to be flagged or if the aggregate data is so bad that state estimator can’t solve. Modern EMS systems incorporate data quality checks within their algorithms. However, how this requirement is phrased will dramatically impact the compliance risk an organization faces.

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Darnez Gresham On Behalf of: Thomas Mielnik, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3

Selected Answer: No

Answer Comment:

The MidAmerican Energy Company (MEC) has concerns with redundancy and technical complications with the TOP-010 standard as proposed. The data quality objective can be simplified into a single requirement in either TOP-010-1 or TOP-001-3 which is for entities to have tools or processes that consider data quality to reasonably assure a reasonably high confidence that the system is in a reliable state. Existing Energy Management Systems (EMS) and Real-Time Contingency Analysis (RTCA) tools already have this capability.

Redundancy:

The MEC recognizes that FERC directed the drafting team to address missing data quality issues based on the 2003 blackout report. However, existing standards TOP-001-3 and TOP-003-3 already require effective monitoring and control which includes proper data quality.

As an example, R13 of TOP-001-3 sets clear requirements that a real-time assessment must be performed at least once every 30 minutes. That requirement includes the identification and consideration of data quality to provide successful assessment solutions at least once every 30 minutes.

TOP-001-3 R13 requires TOPs to have operating processes or procedures that address issues bad data detection and identifications that are likely to cause assessment failures such as non-convergence or invalid solutions.

All TOPs assessment tools already consider bad data detection and identification from embedded software algorithms which are pre-requisites for successful execution of SE/RTCA. TOP's engaged in monitoring the execution of their assessment tool(s) already address problems with data input quality and assessment quality.

Assessment tools must have robust data quality input and assessment capabilities to detect and identify problem(s) with any single piece of data (out of thousands of inputs) especially if that particular bad input (or limited set of bad input data) did NOT affect overall successful performance of the tool.

Technical Compliance Complications that Distort the Reliability Goal:

The zero defect nature of compliance, until fixed, drives unnecessary costly EMS / RTCA system upgrades without measureable system reliability improvements. The proposed TOP-010 standards introduce vague and unclear formulations that will cause misunderstandings during compliance audits. Therefore, it is better to revise TOP-010 to a single requirement or revise TOP-001-3 or TOP-003-3 with an additional simple requirement for entities to have tools or processes that considers data quality to reasonably assure a high confidence that the system is in a reliable state.

Assessment tools use thousands of input data points including analog measurements and switching device statuses. Therefore, the reliability goal(s) are that the assessment tool has bad data detection and identification algorithms that allow the assessment tool to solve, and notify / log the system operator of bad data, and alarm if the bad data may compromise the assessment or solution.

Identifying vague input data issues such as "analog data not updated" or "data identified as suspect" is problematic from a compliance standpoint. Some Energy management Systems (EMS) simply do cannot identify all suspect data and therefore the zero defect compliance expectation to identify all suspect data or all bad analog data is technically infeasible. The reliability goal is a high confidence assessment that the system is in a reliable state. That is very different from the stated compliance zero defect standard as written to identify all "analog data not updated" or identify "all suspect data".

Significant technical problems exist with the TOP-010 requirements when applied to input data received from other TOPs or RC's (either directly or via ICCP). There are no technically feasible mechanism to detect for "manually entered statuses.

An example is detecting a manually entered “CLOSED” circuit breaker status whose actual status is “OPEN”, if such data was received via ICCP.

TOP-010 R3 is unclearly defined as Transmission Operators would have major difficulty in coming up with a conclusion as to what is “the quality of data necessary to perform real-time assessment”. At any moment in time, any specific measurement (or subset of measurements) might either be lost or be detected as “bad”. That does not necessarily mean that the real-time assessment would be inaccurate or invalid. The tool’s accuracy can be measured by other inherent quantitative indicators such as algebraic sum of allocation errors” or “confidence percentile”. An aggregate reasonable confidence percentile measurement would be a sufficient system reliability objective reasonably proving the system was in a reliable state.

TOP-010 R5 introduces unclear terminology of “maintaining the quality of any analysis used in real-time assessment”.

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

PGE thanks the drafting team for there efforts regarding the development of this proposed standard. After meeting with the SMEs involved with the proposed standard, they've provided the following:

SUMMARY

- We recommend a “No” vote on TOP-010-1 at this time because we feel additional clarity is needed.
- Submit comments on the following:
    - Requesting clarification on the meaning of *analysis* and *Real-time Assessments*. (Human or machine.)
    - If R5 is addressing the knowledge or ability of operators, it belongs in PER-005, not here.

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: No

Answer Comment:

R1, R2, R3, & R4: Duke Energy questions the use of the term “analysis” in R2 and R4, attributable to the BA, but is not present in R1 and R3 that is attributable to the TOP. The use of the term analysis in this context suggests that the BA has some sort of responsibility to carry out analyses similar to that of the RC or TOP. We disagree with this premise. Also, we question why the term “analysis” is not present in R1 or R3. The TOP does in fact have responsibilities to carry out analyses, and this should be acknowledged in R1 and R3. Duke Energy suggests that all references to the BA performing an analysis be removed in all attributable requirements, and that analysis that are expected to be performed by the TOP be referenced in requirements attributable to it.

R5: We request further clarification on the use of the phrase “analysis inputs” in the Rationale of R5, as opposed to the use of the term “analysis” in the wording of R5. Is the use of “inputs” meaning other types of data or operational conditions that aren’t described in R1-R4? More clarification regarding what is meant by the phrase “analysis inputs” would be helpful.

R7: Duke Energy requests further explanation on what it meant by the use of the term “processor” in regards to the failure of a Real-time monitoring of an alarm processor. Is this referring to independent hardware that monitors EMS/SCADA or independent processes within the EMS system? Is separate hardware necessary, or will separate processes be sufficient? Should this be something that is housed outside of the EMS? We feel that an example of what is meant by independent (does this mean external?), as well as “processor” would enhance clarity in this requirement.

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
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
Mark Schultz	City of Green Cove Springs	FRCC	3
Chris Adkins	City of Leesburg	FRCC	3
Ginny Beigel	City of Vero Beach	FRCC	9

Voter Information

Voter | **Segment**

Carol Chinn | 4

Entity | **Region(s)**

Florida Municipal Power Agency

Selected Answer: No

Answer Comment:

In part 1.1 of R1, if the bulleted list is intended to be an example list, then the examples should not be given part numbers but should be rolled up into the main sentence. If it is intended to be a minimum set of criteria, then “but not limited to” should be replaced with “at a minimum”.

In part 2.1 of R2, if the bulleted list is intended to be an example list, then the examples should not be given part numbers but should be rolled up into the main sentence. If it is intended to be a minimum set of criteria, then “but not limited to” should be replaced with “at a minimum”.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

ATC supports the comments submitted by the MRO NSRF.

However, raise the following question: Does having a process or procedure support your quality of Real-time data? It’s not the process or procedure but rather what systems do you have in place to alert the TOP/BA that there is an issue with your data (R1.1 – R1.2).

R1 and R2:

o It can be very difficult to identify some of the real-time data quality problems listed in this Standard, particularly analog data that is not updating. Many current systems do not have the capability to easily detect this for all analogs, and adding this capability for all data points could require extensive Software, database, and/or Hardware (for performance reasons) changes that cannot be easily or quickly implemented.

As real-time telemetry becomes more de-centralized in the field and as we are required to rely more and more on data from other entities (via ICCP), it becomes more and more difficult to detect data that is out of range. Putting this requirement on an entity that has o   no control over the source of the data or how it is provided seems to put an unfair regulatory burden on that entity.

o   Most of the real-time data quality criteria seem focused on analog data, but incorrect digital data can have a greater impact on analysis results than incorrect/stale analog data. However, identifying non-updating digital data can be even more difficult than identifying non-updating analog data.

o   How do we prove to an auditor that we identified all instances of data with poor quality?

o   These requirements seemed focused on evaluating the quality of incoming real-time data. Are there any requirements for providing accurate quality codes with data? For example:

§ Both ICCP and some RTU protocols support including quality codes with data values. For example, if an entity receiving ICCP data relies on these quality codes to at least partially determine the quality of a data point, then the received quality codes need to be accurate.

§ Both ICCP and some RTU protocols support including time-stamps of the most recent change of a data point value.   Some systems use this received time-stamp when processing the data, and it can impact applications used by operators, including where a new alarm for that point appears in an EMS/SCADA alarm list. Receiving an incorrect time-stamp can negatively impact the information and results provided to an operator.

R3 and R4:

o   What is considered sufficient notification to an operator of real-time data quality problems? If quality codes are shown on EMS/SCADA displays, an operator may not look at the displays with data quality issues. But if alarms are generated to notify the operator, the increase in alarm volume may detract the operator's attention from more important alarms.

o   Summarizing the quality of thousands of real-time measurements for an operator may not be something existing systems can easily do. This may require software and possibly hardware additions to an EMS/SCADA.

R5: There is no guidance provided for a Transmission Operator to create criteria to evaluate the quality of analysis used in its Real-time Assessments. If an auditor will be expected to review the criteria used by a Transmission Operator, the guidelines that will be provided to auditors for this purpose should be listed here.

R7: With current EMS/SCADA architectures, it can be difficult to define what comprises the "alarm processor". While requirements R1-R4 of this Standard may cover the quality of the telemetered inputs to the EMS/SCADA, there are many EMS/SCADA components used after that to make operators aware of alarms. It is not just a specific alarm processing program, but also includes

· things such as the EMS/SCADA data dissemination programs, the EMS/SCADA User Interface application, audible alarming capabilities, even the operator console hardware itself. Should this requirement be re-worded to make it clearly cover the ability of the system to make alarms available to operators and not imply it is limited it to a specific “program”?

VSLs:

o R3 & R4: It is not clear from the wording of the single VSL level (which is Severe) if a violation of this Standard is incurred only if there are NO indications of quality of real-time data. If the meaning is to include situations where one or a few points with bad quality are missed (i.e., not notified to an operator) than assigning a Severe VSL seems inappropriate, and several levels of violations should be implemented.

o R6: Is it correct that a violation of this Standard is incurred only if there are NO indications provided to operators of poor quality of analysis results, and that missing some number of these instances is not a violation of this Standard? If the intent is to consider even a single miss a violation then assigning it a Severe VSL seems inappropriate, and several levels of violations should be implemented.

R7: Is it correct that occasional failures of the independent alarm process monitor are not violations of this Standard?

Document Name:

Likes: 1 Grand River Dam Authority, 3, Wells Jeff

Dislikes: 0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer: No

Answer Comment:

This standard creates a double jeopardy situation. Requirement R1 Part 1.2 of this standard specifies the TOP shall include actions to coordinate resolution of Real-time data quality discrepancies in its Operating Process or Operating Procedure. These actions are also required by proposed TOP-003-3 Requirement R5 Part 5.2 which requires a process to resolve data conflicts for the data required by the data specification in Requirement TOP-003-3 R3. If that data specification requires the provision of Real-time data, then TOP-003-3 Part 5.2 requires a process to resolve data conflicts and quality discrepancies with that Real-time data.

Suggested wording: **R1.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data**, excluding Real-time data already addressed by TOP-003-3 R5 Part 5.2,** necessary to perform its Real-time monitoring and Real-time Assessments.

Document Name:

Likes: 0

Dislikes: 0

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1 -

Selected Answer: No

Answer Comment:

CenterPoint Energy feels R1.1.2 (Analog data not updated within a predetermined time period) brings more of a compliance burden than a reliability benefit. CenterPoint Energy has confidence System Operators investigate and communicate these issues upon suspicion; however, defining a predetermined time period for a data quality code check including each individual piece of data poses a threat to the System Operator's focus monitoring important issues on the grid. CenterPoint Energy also realizes there is a challenge in deciphering whether or not a value has simply not changed in a predetermined time period or if that value hasn't updated. CenterPoint Energy recommends the SDT clarify that 1.1.2 refers to the universe or a pre-defined subset of data and not specific to any one, individual piece of data.

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 does not support the proposed Reliability Standard TOP-010-1. We also believe that these requirements are too prescriptive (the “how”) and is moving away from the result-based approach (the “what”).

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - PPL NERC Registered Affiliates - 1,3,5,6 - SERC,RFC

Group Information

Group Name: PPL NERC Registered Affiliates

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E and KU Energy, LLC	SERC	1,3,5,6
Brenda Truhe	PPL Electric Utilities Corporation	RFC	1

Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
Dan Wilson	LG&E and KU Energy, LLC	SERC	5
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
PPL NERC Registered Affiliates	SERC,RFC

Selected Answer: No

Answer Comment:

Comments: These comments are submitted on behalf of the following PPL NERC Registered Affiliates (“PPL”): Louisville Gas and Electric Company, Kentucky Utilities Company and PPL Electric Utilities Corporation. The PPL NERC Registered Affiliates are registered in two regions (RFC and SERC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

The PPL NERC Registered Affiliates believe if additional requirements are necessary for TOP’s and BA’s to address the quality of their Real-time data, then these requirements should be included in the proposed Reliability Standard TOP-003-3. Per TOP-003-3 (pending regulatory approval) , TOP’s and BA’s are required to maintain a documented specification for the data necessary to perform its Real-time monitoring and Real-time assessments including periodicity for providing data and a mutually agreeable process for resolving data conflicts. Therefore, adding additional requirements to TOP-003-3 to address the quality of the TOP and BA specified data is less of a compliance burden to stakeholders than creating a new standard.

If the SDT chooses to continue with the proposed TOP-010 standard, we request the sub-requirements R1.1.1 thru 1.1.4 and R2.1.1 thru 2.1.4 be removed from the proposed TOP-010 to allow entities the flexibility to write an Operating Process or Operating Procedure tailored to their system and their Reliability Coordinators specifications where applicable.

Document Name:

Likes: 0

Dislikes: 0

Thomas McElhinney - JEA - 1,3,5 - FRCC

Group Information

Group Name: JEA

Group Member Name	Entity	Region	Segments
Ted Hobson	JEA	FRCC	1
Garry Baker	JEA	FRCC	3
John Babik	JEA	FRCC	5

Voter Information

Voter	Segment
Thomas McElhinney	1,3,5
Entity	**Region(s)**
JEA	FRCC

Selected Answer: No

Answer Comment:

The independent monitoring needs to be better clarified. Does independent mean another system besides EMS? We also believe that the terms quality and indicators are vague.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SERC,SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
John Allen	City Utilities Springfield Missouri	SPP	1,4
Darryl Boggess	Western Farmers Electric Cooperative	SPP	1,5
Donald Hargrove	Oklahoma Gas and Electric	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Robert Hirchak	CLECO	SPP	1,3,5,6
J. Scott Williams	City Utilities of Springfield Missouri	SPP	1,4
Sing Tay	Oklahom Gas and Electric	SPP	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5
Kyle McMenamin	Xcel Energy	SPP	1,3,5,6

Voter Information

Voter	**Segment**
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	MRO,WECC,SERC,SPP

Selected Answer: No

Answer Comment:

Following are the same comments we provided on IRO-018-1 draft. They are generally applicable to the proposed TOP-010-1 Standard also.

We do not believe the issues addressed by the FERC directive rise to the level of requiring a reliability standard. The intent of the directive and the resulting actions to be taken by the various entities would be better served by an official Guideline rather than a generic standard. Forcing this into a Standard requires a one-size fits all approach that is leading to varied interpretations on “quality” and “adequacy” and may not enhance reliability of the BES.

We believe the requirements in general could be improved to be more results based. As written, they largely will only result in identifying deficiencies after the fact when doing event analysis. An entity may have a process or procedure as required, but they could miss a piece of data or fail to identify fully the impact a quality issue may have upon their situational awareness. Simply having the process does not result in increased reliability.

Most entities already have a process in place to alarm or indicate data quality as needed to maintain reliability. Entities are already required to operate reliably, within SOLs and IROLs, etc. The creation of this standard as written would serve only to document that process and put it under auditable enforcement – with no discernible impact to maintaining reliability. In order to make this standard truly results based, there needs to be some identification of the quality level, or data quality thresholds that must be maintained in order for reliability to be maintained. Then that level (or quality of the data measurements) must be maintained per the standard.

We suggest that there needs to be more direction given by the Standard in a few areas. One is that the applicable entity should be determining a data range, time periods, number of manually entered values, etc. that can degrade analysis to the point reliability is threatened (R1.1.1-R1.1.4).

We also find it problematic when an entity may not "own" the data and is simply receiving a quality flag from a sender. The RC for example may not receive an accurate quality flag or the quality flag is corrupted in translation over ICCP. Also, there is no requirement that the measurement devices even be of a particular accuracy. For example the quality threshold may be more narrow than the accuracy of the device.

The use of the term "suspect" in R2.1.4 in TOP-010-1 could lead to an interpretation that the operator "should have suspected" the data was incorrect. The word "suspect" is used in some EMS packages as an identifier for garbage or data that is suspect. We recommend the word be evaluated and replaced.

R3 is very problematic in that it infers there is a level of in-adequacy that studies must not fall below when requiring a level of "quality" to be maintained. This seems to be an attempt to not use the word "adequate". Without defining the required level of quality, there is no way an entity can be compliant. Any entity may experience some reduced level of quality, but may still have acceptable performance from their studies without taking action to correct or mitigate the data. As written, the entity would be in violation for simply failing to "maintain" the level of quality. Perhaps R3 could be written this way:

R3. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to maintain an acceptable level of quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

3.1. Criteria for determining the minimum quality of any analysis used in its Real-time Assessments; and

3.2. Actions to resolve unacceptable quality deficiencies in any analysis used in its Real-time Assessments.

R4 seems to be applicable to situations where a tool is used to perform the RTA. This can become problematic when the assessment is simply an evaluation done by reviewing data and determining that no changes on the system have occurred such as could occur with a TOP who has only a few BES elements and does not possess an EMS or RTCA style "tool".

We suggest that altering the phrase “independent alarm process monitor” could be beneficial. As stated, the phrasing seems to suggest particular processes or tools rather than the intent to just have an “independent process” to monitor the alarming system. We suggest the change as:

R5. Each Reliability Coordinator shall utilize a process to independently monitor its Real-time monitoring alarm process monitor in order to provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The SRC fails to see the reliability risk that this project is intending to address. The August 14 Blackout as well as the 2011 Southwest Outage have thoroughly and exhaustively investigated, reported upon, and the root causes mitigated appropriately. Therefore, pointing to the need for this project based on mitigated, historical events falls short of identifying the reliability risk that this is intended to “fix.” If, for example, WECC continues to have a vested interest in further mitigating the 2011 Southwest Outage though standard development, we suggest this project be migrated into a regional standard for WECC. Lastly, the SRC believes that, absent a Standard specific for tools, a RC, TOP, or BA would, in fact, have violations of existing operational Requirements if they do not provide adequate monitoring and tools to their operators (i.e. other “things” would happen).

Further, the Requirements as written, "…to address the quality of the Real-time data necessary…" are ambiguous, lack consensus about how to measure, and do not rise to the level of a NERC Standard.

This proposed project appears to be well-suited for a guideline document as opposed to a Standard. As written, the SAR appears to intend to write a "how" not "what" Standard (*i.e.*, it does not appear to be a results-based standard). The SRC believes that the existing Standards (*i.e.*, IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (*i.e.*, without defining the "how"), which is appropriate. In the alternative, this could be considered a process to be used for Certifying new entities, in line with a methodology developed by the ERO and registered entities for assessing adequacy of tools for addressing the "quality" of real-time data, for assurance that RC, BA and TOPs have the ability to monitor appropriately in accordance with existing, performance-based Standards Requirements.

The SRC notes that the tools available to operators have progressed well beyond those available in 2003. If defined tools would have been hardcoded in a standard at that time, it would have limited focus and investment to those things that were in the standard. Further, expanding on our point above, the SRC believes that the "what" regarding tools is more appropriately captured in the certification expectations for BAs, RCs, and TOPs. Additionally, it would be appropriate for Regions to evaluate tools as part of the Registered Entity's Inherent Risk Assessment (IRA). This would include the scope of tools, backups, etc. and would provide an adaptable approach that would encourage continuous improvement.

Additionally, the SRC recommends that NERC coordinate with the NATF to encourage inclusion of an ongoing "care and feeding" of tools evaluation and information sharing in their efforts with the provision that they make information on good practices available to the wider NERC community so that non-members can learn from the innovation of others.

Finally, to avoid these issues in the future and to support communicating to FERC when a Standard is not needed and another tool is more suitable, the SRC suggests that future SARs be voted on by industry to determine whether they should proceed as a Standards project or another means is a more appropriate method through which to achieve the SAR's objective.

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

Jack Stamper - Clark Public Utilities - 3 -

Selected Answer: No

Answer Comment:

Some of the criteria listed in R1.1 is confusing. Data outside of prescribed data range would more likely indicate unusual system conditions rather that a data quality issue. We are currently unsure how the monitoring of these criteria could be implemented without additional software. Also, since implementation is part of the Measurement we would assume some logging of this implementation would be necessary to prove compliance which is also a process without and obvious means of accomplishment. There needs to be some substantial guidance or technical discussion providing information on what would be the expectations for utilities to be in compliance with this standard.

Document Name:

Likes: 0

Dislikes: 0

Megan Wagner - Westar Energy - 6 -

Selected Answer: No

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: Project 2009-02

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Michael Forte	Con Edison	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
Kelly Dash	Con Edison	NPCC	3
Michael Jones	National Grid	NPCC	3
David Burke	Orange and Rockland Utilities	NPCC	3
Peter Yost	Con Edison	NPCC	4
Wayne Sipperly	New York Power Authority	NPCC	4

Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7

Voter Information

Voter

Ruida Shu

Segment

1,2,3,4,5,6,7

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer: No

Answer Comment:

Each requirement is unique to a particular functional entity. Requirements can be eliminated by having each requirement refer to Transmission Operator and Balancing Authority.

Similarly to IRO-018-1, language in R1.1 uses “but not limited to”. That language is too open ended and cannot be audited. Compare it to R3 use of “shall include”. “But not limited to” only belongs in a Measurement.

R2 is a bit ambiguous in whether a single data point of bad quality needs to be flagged or if the aggregate data is so bad that the state estimator can’t solve.

Suggest replacing the word “any” from R5 and R6 (relative to “any analysis”) and replacing with “reliability related” as “any” could be too broadly applied or interpreted. Additionally, the term analysis is broad. Standards related to Project 2014-03, approved through NERC as of this time, define such things as Real Time Assessments and Operational Planning Analysis. It’s not exactly clear what analysis would be referring to.

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer: No

Answer Comment:

R5: Need to clarify. What is "quality of any analysis used"? Need to clarify & better define. How is SO notified & Will SO need evidence?

R7: Regarding "independent alarm process monitor (IAPM)": Need more clarity; is this separate from the SCADA data /SCADA system? Is an IAPM separate from SCADA system? Need more clarity.

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5

Voter Information

Voter

Ben Engelby

Segment

6

Entity

ACES Power Marketing

Region(s)

Selected Answer: No

Answer Comment:

(1) The standard has significant burdens on System Operators to demonstrate compliance. Requirements R2, R3, and R5.2 expect solution frequencies every 5 minutes, 12 times an hour, 288 times a day. Does each quality deficiency occurring during this period need to be resolved? A RTU communication issue lasting only 10 minutes would impact a minority number of these instances and generate unnecessary work for a system operator. We believe the SDT should provide some qualifier for this requirement.

(2) We believe this standard has the potential to add to the System Operator's workload and take their attention away from their duties of monitoring system reliability. NERC has spent significant efforts to educate industry on situational awareness and human performance topics, including cognitive overload where too much stimuli affecting a System Operator will have negative effects on their performance.

(3) The standard also introduces potential double jeopardy concerns between requirements TOP-010 R2 and BAL-005 R5. At the time of the webinar, the SDT did not look into these possibilities. However, NERC did later respond to the potential double jeopardy with the following statement:

"R5 in proposed BAL-005-1 is limited to information associated with Reporting ACE. R2 in proposed TOP-010-1 applies to Real-time data necessary to perform the BA's analysis functions and Real-time monitoring. These functions go beyond BAL-005 as described in the NERC Functional Model and existing and proposed TOP and IRO standards. Double jeopardy is never an issue because NERC Rules of Procedure include provisions for handling incidences of non-compliance with two or more requirements. Specifically, NERC or the regional entity would issue a single penalty or sanction as called for in the Rules of Procedure (Appendix 4B, Section 2.5)."

We disagree with this approach, as the ROP is focused on being in violation of a single requirement or sub-requirement, not to separate requirements. The issue of double jeopardy could occur when there is an event based on poor ACE data quality, which could also implicate TOP-010-1. While TOP-010-1 contains additional data, it is possible to be in violation of two requirements for the same instance, which is the very definition of double jeopardy. The NERC ROP does not provide relief for this situation.

(4) We have concerns with the potential impact to a System Operator's general awareness of the system. The System Operator will now be spending more time logging and performing actions strictly for compliance instead of BES Operation activities. While we understand that the proposed standard allows the entity to determine the amount of operator action needed, can this be similarly defined in a Process or Procedure? We have concerns that an auditor may not interpret the standard to allow other employees to mitigate any data or analyze errors, such as an EMS Engineer or other support personnel. We request that the SDT consider revising the standard to clarify that a System Operator does not specifically have to be the one who mitigates such issues. Furthermore, how does the SDT expect entities to show compliance with "implementation" of their Process of Procedure?

(5) The proposed standard includes requirements that should enhance, not detract, from the System Operator's situational awareness since it is based on recommendations from the RTBPTF report. The SDT is mindful that System Operators need to remain focused on relevant real-time information while carrying out their duties. The proposed requirements should provide entities the flexibility to determine which operating personnel carry out required actions. Implementation could be demonstrated through evidence that the Operating Process or Procedure is used for its intended purpose. This evidence which might include checklists, operator logs, or operations support logs, for example.

(6) Compliance with the proposed requirements is not evaluated by counting quality codes on data points. The measures, VRFs, and VSLs are constructed to evaluate the capability-based performance requirements, as described in section 2.4 of the SPM. This section states that Capability-based Requirements are defined capabilities needed by one or more entities to perform reliability functions which can be measured by demonstrating that the capability exists as required.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer: No

Answer Comment:

ReliabilityFirst offers the following comments for consideration:

1. **Requirement R3 and R4**

   i. **It is unclear as to what the phrase “indication(s) of the quality of the Real-time data” is referring to. RF requests clarification on the term “indications” and what this involves.**

   i. **Also, since the System Operators work for the respected TOP or BA, it is unclear whom at the respected TOP or BA will be providing “indications” to the System Operators. As written, the System Operators (working for the TOP or BA) could provide indications to themselves. This does not seem to be the intent of the Requirement.**

2. **Requirement R6**

   i. **It is unclear as to what the phrase “indication(s) of the quality of any analysis…” is referring to. RF requests clarification on the term “indications” and what this involves.**

   i. **Also, since the System Operators work for the TOP, it is unclear whom at the TOP will be providing “indications” to the System Operators. As written, the System Operators (working for the TOP) could provide indications to themselves. This does not seem to be the intent of the Requirement.**

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment:

Comments: ERCOT reiterates its comments above as applicable to TOP-010-1. Should NERC continue this project, however, ERCOT provides the following comments by requirement:

Requirements R1 and R3/Requirements R2 and R4

ERCOT respectfully recommends that requirements R1 and R3 and Requirements R2 and R4 be combined. Because the need to address data issues generally arises as a result of a data indicator or the need for manual data intervention by system operators, the value of a process to address such issues without the context of time or need is significantly diminished. Hence, ERCOT proposes the following:

R1. Each Transmission Operator shall provide its System Operators with indication(s) of the quality of Real-time data necessary to perform its Real-time monitoring and Realtime Assessments. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R1.1 The Transmission Operator shall initiate actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data when failure or degradation is indicated.

R2. Each Balancing Authority shall provide its System Operators with indication(s) of the quality of Real-time data necessary to perform its analysis functions and Real-time monitoring. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R2.1 The Balancing Authority shall initiate actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data when failure or degradation is indicated.

Requirements R5 and R6

ERCOT respectfully recommends that requirements R5 and R6 be combined. Because the need to address issues with real-time analyses generally arises as a result of an indicator that a particular analysis did not complete, is offline or there is a need for manual intervention by system operators, the value of a process to address such issues without the context of time or need is significantly diminished. Additionally, the availability of back up or offline processes for real-time analyses mitigates the risks associated with an issue or outage of analysis capabilities. Hence, ERCOT proposes the following:

R3. Each Transmission Operator shall provide its System Operators with indication(s) of the tool(s) used in its Real-time monitoring and Real-time Assessments are functioning as intended. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R3.1 The Transmission Operator shall initiate actions to resolve any issues internally and to coordinate resolution of any data issues that are impacting such tool(s) with entity(ies) responsible for providing data inputs to such tool(s) when failure or degradation is indicated.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: No

Answer Comment:

R1 and R2: The requirements are vague as to what constitutes quality. Do we consider out of tolerance? High value? Low value? What is too high? What is too low?

R3 and R4: If quality alarms are generated to alert the operator, the increase in alarm volume may distract the operator from more important alarms. If quality codes are shown on the EMS/SCADA displays, an operator may not look at or notice the displays with data quality issues.

Summarizing the quality of thousands of real-time measurements for an operator may not be something existing systems can easily do. This may require software and possibly hardware additions to an EMS/SCADA.

R5: TOP-001-3 R13 requires that a real-time assessment is performed at least once every 30 minutes. In order to resolve any issues with the quality of analysis for the real-time assessment outside of normal business hours may require staff to come into the office to resolve which may take more than 30 minutes. This would put an entity out of compliance with TOP-001-3, unless staffing is increased which may not be feasible.

There is no guidance provided to create criteria to evaluate the quality of analysis used in Real-time Assessments. There could be discrepancies between an auditor and an entity over what is acceptable criteria. Guidelines that will an auditor could be expected to review should be listed.

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: No

Answer Comment:

The criterion specified in R1.1 and R1.2 is too prescriptive. The requirements as written are requiring System Operators to monitor the quality of all data specified per proposed TOP-003-3 R1. In a Real-time system there are thousands of data points used and having a few of those outside prescribed data range or not updated within a predetermined time period may have no impact on BES reliability. Requiring System Operators to track the quality of all data can be a distraction and an unnecessary burden. ITC believes the intent of the standard is for entities to pay attention to quality of certain pre-identified data used in Real-time monitoring and analysis. However, the future standard TOP-003-3 will result in this requirement being applied to all data used in Real-time monitoring and analysis. Transmission Operators are required to perform a Real-time assessment and these assessments most commonly utilize tools which are designed to reduce dependencies on bad, invalid, or suspect data therefore placing a requirement for evaluating invalid or suspect data in Real-time does not provide any reliability benefit.

The proposed TOP-001-3 R1 requires that each Transmission Operator (TOP) shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. Proposed TOP-001-3 R10 requires TOP to determine SOL exceedances and TOP-001-3 R12 requires TOP to not operate outside IROL for more associated IROL Tv. These requirements together inherently imply that the Transmission Operator should ensure quality of data used in Real-time to get the desired outcome from the Real-time Assessment which is to maintain reliability of its area by monitoring SOLs and IROLs and taking appropriate actions. The proposed TOP-010-1 R1 seems to be specifying ‘How to’ comply with these requirements which does not meet the result base standard practice. In addition, the rationale for R13 in proposed TOP-001-3 states “The Transmission Operator’s Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements and how to adapt to conditions where processes, procedures, and automated software systems are not available (if used)”. Thus, the actions needed on data quality are already expected in the Operating Plan to ensure the desired outcome. Therefore, a new requirement for data quality may be redundant.

In summary, it is appropriate to have an Operating Procedure to maintain and address quality of data used in Real-time Assessment. However, the monitoring and analysis of data quality for all data in Real-time is not practical and does not add value to reliability. Real-time Assessment tools used by TOPs have processes to manage bad data and provide valid results. Data quality should be monitored outside of the Real-time operator environment wherein staff other than System Operators can analyze patterns of data to identify data quality issues that truly impact Real-time analysis. The measures specified in TOP-010-1 indicate dated operator logs and voice recordings as evidence for compliance which will require the System Operator to monitor quality of all data. Also, the expectation of the System Operator to review data quality in Real-time for every data point is overkill.

TOP-010-1 R3 is redundant when compared to TOP-010-1 R6. R6 is requiring an indication of quality of analysis used in Real-time Assessment wherein R3 is requiring indication of quality of data used in Real-time Assessment. The quality of analysis used for Real-time Assessments may be an indicator of quality of data used in Real-time Assessment thus having a requirement on both is redundant and can result in multiple noncompliance incidents for a single problem. For example, a single bad Real-time data point may constitute a violation of TOP-010-1 R3 and since this data is used in Real-time Assessment it may also cause a violation of TOP-010-1 R6.

ITC supports TOP-010-1 R7 having an independent processor to monitor Real-time alarm system because it provides value due to the heavy reliance on alarms by System Operators for situational awareness. However, the standard should specify if the unavailability of independent processor creates a violation of standard requirements. Although, the implementation plan of 12 months for R7 is unrealistic as compliance with this requirement may require entities to procure and implement new tools which is a lengthy process.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE recommends adding the Balancing Authority (BA) function to the applicability of R5 and R6. While it could be argued that a BA does not have to perform Real-time Assessments per a Reliability Standard requirement (in other words explicitly stated as required to do Real-time Assessments), its actions to maintain frequency are effectively as assessment based on Real-time data.

Texas RE suggests using language from the rational to make TOP-010-1 R5 and R6 clearer. The requirements address "quality of analysis", which could depend on many factors, while the rationale uses the language "to address issues related to the quality of the analysis inputs used for Real-time Assessments".

Texas RE recommends revising the phrase "with indication(s) of" used in proposed TOP-10-1, R3, R4, and R6 as it is vague. The purpose of TOP-10-1, R3, R4, and R6 appears to be to ensure that the results of the required evaluations of potential Real-time data quality discrepancies are communicated to System Operators so that information regarding such data discrepancies could potentially be incorporated into Real-time monitoring, analysis functions, and Real-time assessments. Accordingly, registered entities should be required actually to provide the actual information from their data quality assessments to their System Operators. Texas RE would suggest substituting "relevant information and/or analyses concerning" for "with indication(s) of" to require appropriate, relevant information and/or any analyses of the quality of Real-time data be communicated to System Operators, not merely indications of data quality.

The reference to "with indications of" in the corresponding measures should also be revised along these lines. However, the types of evidence identified in the measures satisfy the proposed "relevant information and/or analyses concerning" standard.

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment:

R4 states "Each Balancing Authority shall provide its System Operators with indication(s) of the quality of Real-time data necessary to perform its analysis functions and Real-time monitoring." Are the analysis functions limited to real-time analysis, or could this be interpreted to apply to study and after the fact analysis? We believe that this needs to be clear.

R5. What does "maintain the quality" mean? What if the quality of the analysis is not currently what it should be, then this requirement appears to preclude improving that quality.

R6 requires "indication(s) of the quality of any analysis"; how is quality defined? We believe this is very ambiguous as written and for us internal discussions resulted in multiple opinions. We believe that the term Quality needs to be concisely defined within the requirement.

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery,1

Selected Answer: No

Answer Comment:

This standard is too vague and needs additional clarification. We support some of the comments from MRO.

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: No

Answer Comment:

Southern believes that the criteria in R1.1 should be limited to the BA/TOP's ability to monitor and assess the current/expected condition of its BA/TOP area within the capabilities of its monitoring tools not including the criteria listed in R1.1.1-R1.1.4.

Each TOP has the inherent responsibility to protect the integrity of the system in its BA/TOP area and to not contribute or cause any system violations in adjacent BA/TOP areas. In order to fulfill this responsibility, the BA/TOP performs monitoring through the information collected from the modeled facilities in its TOP areas to accurately assess the state of the system. The BA/TOP is constantly evaluating the quality of data received to ensure it has an accurate state of system conditions to perform real time assessments. To impose a new standard focusing on data quality would only serve as administrative in nature and would not provide any substantial increases in reliability.

Document Name:

Likes: 0

Dislikes: 0

3. Do you agree with the Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

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

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

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

AEP cannot determine the adequacy of the proposed implementation plan until more clarity is provided on the obligations themselves. If it is determined that the obligations *are* very granular (i.e. “per data point”), the implementation plans would be insufficient.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

We do not agree with the need for the standard, and therefore do not agree with the proposed implementation plan.

Document Name:

Likes: 0

Dislikes: 0

Tyson Archie - Platte River Power Authority - 5 -

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

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

Xcel Energy feels that the implementation timeline is too short. We support the comments of the MRO NSRF recommending a 60 month implementation to allow entities adequate time to assess tools and complete necessary upgrades.

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: No

Answer Comment:

The implementation plan is too short if entities need to specify, order and deploy new or modified Energy Management Systems (EMS) that can monitor, track, and report real-time data quality and availability in accordance with IRO-018 and TOP-010. Entities should be given an implementation plan with up to 60 months for new EMS software and systems.

The key is to allow entities the proper time to assess their tools and complete the right upgrades once. While prompt actions are good, forcing entities to assess, order, and deploy equipment in 12 or 18 months will lead to errors and possibly more risk of serious outages and problems in the short term.

The standard objective needs to be modified to a feasible reliability objective such as the assessment provides a reasonably high confidence interval that the system is in a reliable state. TOPs and BAs should be given much more time to make appropriate changes to their tools and EMS systems and to test their capabilities to detect and implement operating plans to respond to bad data detection and identification. The time needed to modify, specify, install, adjust and test systems or tool to meet the proposed standard should be, at a minimum, 3 to 5 years.

Document Name:

Likes: 0

Dislikes: 0

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer: No

Answer Comment:

PJM does not support the proposed standards for the reasons noted in 1 and 2 above.

Document Name:

Likes: 5

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Long Island Power Authority, 1, Ganley Robert
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Darnez Gresham On Behalf of: Thomas Mielnik, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3

Selected Answer: No

Answer Comment:

The standard objective needs to be modified to a feasible reliability objective such as the assessment provides a reasonably high confidence interval that the system is in a reliable state. TOPs and BAs should be given much more time to make appropriate changes to their tools and EMS systems and to test their capabilities to detect and implement operating plans to respond to bad data detection and identification. The time needed to modify, specify, install, adjust and test systems or tool to meet the proposed standard should be, at a minimum, 3 to 5 years.

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

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: No

Answer Comment:

Duke Energy is not in favor of the proposed 12 months and 18 months staggered implementation plan. In one of our previous comments, we requested that additional information be provided regarding the what is meant by the use of the terms alarm process monitor. If this alarm process monitor is something that would necessitate an entity to go out and procure something that is does not currently own, then additional time would be needed. The timeframe of 18 months for all requirements seems more appropriate.

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
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
Mark Schultz	City of Green Cove Springs	FRCC	3
Chris Adkins	City of Leesburg	FRCC	3
Ginny Beigel	City of Vero Beach	FRCC	9

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer: No

Answer Comment:

If TOP-003-3 is approved at the same time or after TOP-010-1, then the result of the implementation plan as drafted is that requirements to have quality data become effective at the same time as requirements that could cause the TOP and BA to be seeing new data for the first time. R5 of TOP-003-3 could result in a large volume of new data, so more time should be afforded to the receiving TOP and BA to become familiar with and begin utilizing that new data. We recommend the timeframes for **implementation of TOP-010-1 be modified to be 18 months and 24 months**, at a minimum, to allow for separation from TOP-003-3 R5. A section could be added that addresses a scenario where TOP-003-3 is approved well before TOP-010-1.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC supports the comments submitted by the MRO NSRF as it relates to TOP-010-1.

The implementation plan is too short if entities need to specify, order and deploy new or modified Energy Management Systems (EMS) that can monitor, track, and report real-time data quality and availability in accordance with IRO-018 and TOP-010. Entities should be given an implementation plan with up to 60 months for new EMS software and systems.

The key is to allow entities the proper time to assess their tools and complete the right upgrades once. While prompt actions are good, forcing entities to assess, order, and deploy equipment in 12 or 18 months will lead to errors and possibly more risk of serious outages and problems in the short term.

Document Name:

Likes: 1 Grand River Dam Authority, 3, Wells Jeff

Dislikes: 0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1 -

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:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - PPL NERC Registered Affiliates - 1,3,5,6 - SERC,RFC

Group Information

Group Name: PPL NERC Registered Affiliates

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E and KU Energy, LLC	SERC	1,3,5,6
Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
Dan Wilson	LG&E and KU Energy, LLC	SERC	5
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6

Voter Information

Voter

Brent Ingebrigtson

Segment

1,3,5,6

Entity

PPL NERC Registered Affiliates

Region(s)

SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas McElhinney - JEA - 1,3,5 - FRCC

Group Information

Group Name: JEA

Group Member Name	Entity	Region	Segments
Ted Hobson	JEA	FRCC	1
Garry Baker	JEA	FRCC	3
John Babik	JEA	FRCC	5

Voter Information

Voter	Segment
Thomas McElhinney	1,3,5
Entity	**Region(s)**
JEA	FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SERC,SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
John Allen	City Utilities Springfield Missouri	SPP	1,4
Darryl Boggess	Western Farmers Electric Cooperative	SPP	1,5

Donald Hargrove	Oklahoma Gas and Electric	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Robert Hirchak	CLECO	SPP	1,3,5,6
J. Scott Williams	City Utilities of Springfield Missouri	SPP	1,4
Sing Tay	Oklahom Gas and Electric	SPP	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5
Kyle McMenamin	Xcel Energy	SPP	1,3,5,6

Voter Information

Voter

Jason Smith

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

MRO,WECC,SERC,SPP

Selected Answer: No

Answer Comment:

Based on the proposed standards, 12 months should be sufficient time to simply develop a written procedure and ensure operators are knowledgeable. However, depending on what the final version of the standard looks like, it may be impossible to meet some of the resulting requirements unless systems are replaced. In that case, 36 months may be required.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2

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: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jack Stamper - Clark Public Utilities - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Megan Wagner - Westar Energy - 6 -

Selected Answer: No

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: Project 2009-02

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Michael Forte	Con Edison	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1

Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
Kelly Dash	Con Edison	NPCC	3
Michael Jones	National Grid	NPCC	3
David Burke	Orange and Rockland Utilities	NPCC	3
Peter Yost	Con Edison	NPCC	4
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7

Voter Information

Voter

Ruida Shu

Segment

1,2,3,4,5,6,7

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer: No

Answer Comment:

(1) The implementation plan is too short if entities need to specify, order, and deploy a new or modified Energy Management System (EMS) that can monitor, track, and report real-time data quality and availability in accordance with IRO-018 and TOP-010. Entities should be given an implementation plan with up to 60 months for new EMS software and infrastructure.

(2) The key is to allow entities adequate time to assess their tools and complete the right upgrades once. While prompt actions are good, forcing entities to assess, order, and deploy equipment in 12 or 18 months will lead to errors and possibly more risk of serious outages and problems in the short-term.

(3) In the alternative, if the SDT determines that it will not extend the implementation to 60 months, we ask the SDT to consider making all requirements effective after 18 months. Staggered effective dates has caused significant and unnecessary implementation issues, such as the confusion that occurred with implementing PRC-005 and its various requirements.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Comments: ERCOT's comments above notwithstanding, the proposed implementation plan appears reasonable.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: No

Answer Comment:

12 months may be too short depending on the capabilities of existing systems. More time may be needed to assess the existing capabilities of the EMS/SCADA system and if new systems are needed, time will be required to specify, order and deploy a new EMS system.

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: No

Answer Comment:

ITC supports TOP-010-1 R7 having an independent processor to monitor Real-time alarm system because it provides value due to the heavy reliance on alarms by System Operators for situational awareness. However, the standard should specify if the unavailability of independent processor creates a violation of standard requirements. Although, the implementation plan of 12 months for R7 is unrealistic as compliance with this requirement may require entities to procure and implement new tools which is a lengthy process.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE is concerned the Implementation Plan allows for an increase in risk to the BES if quality is not already being addressed. To ensure reliable operations, Texas RE suggests decreasing the Implementation plan to a more reasonable time period such as the first day of the first quarter after approval for all requirements except R7, which requires TOPs and BAs to utilize an alarm process monitor. Twelve months is not an unreasonable time for the development of an independent alarm process monitor.

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery,1

Selected Answer:

Answer Comment: This standard is too vague and needs additional clarification. We support some of the comments from MRO.

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: No

Answer Comment:

Southern believes that the implementation date should be pushed back to allow time for the industry to determine the appropriate technology that is sufficient for each entity's operations. We also believe that in order to fully comply with the proposed standard, enough time should be allowed for the industry to update their current procedures and/or to create acceptable procedures, provide training to the appropriate System Operators and allow sufficient time for the entities to determine the technology available that is available and appropriate to support their operations, along with the required functionality.

Document Name:

Likes: 0

Dislikes: 0

4. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

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

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

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

The team may want to consider using a more gradient-based approach for R1, R2, and R5, and using more than two VSL categories (driven by the number of elements not considered). If the requirements continue to use two VSL categories only, the High VSL should instead state "excluded at least one but not all of the elements…"

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

We do not agree with the need for the standard, and therefore do not agree with the proposed VRFs and VSLs.

Document Name:

Likes: 0

Dislikes: 0

Tyson Archie - Platte River Power Authority - 5 -

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

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

Xcel Energy believes that the proposed VSLs are not appropriate. The full spectrum of VSLs (Low/Med/High/Severe) should be utilized for each requirement, and that full clarification of what quantifies a violation at each severity level should be disseminated.

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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: No

Answer Comment:

The binary approach to the VSLs seems too severe. Suggest that the drafting team consider revising the VSLs to utilize moderate, high, and then severe if the entity missed one, two, three, or finally all data quality elements.

R3 & R4: It is not clear from the wording of the single VSL level (which is Severe) if a violation of this Standard is incurred only if there are NO indications of quality of real-time data. If the meaning is to include situations where one or a few points with bad quality are missed (i.e., not notified to an operator) than assigning a Severe VSL seems inappropriate, and several levels of violations should be implemented.

R6: Is it correct that a violation of this Standard is incurred only if there are NO indications provided to operators of poor quality of analysis results, and that missing some number of these instances is not a violation of this Standard? If the intent is to consider even a single miss a violation then assigning it a Severe VSL seems inappropriate, and several levels of violations should be implemented.

R7: Is it correct that occasional failures of the independent alarm process monitor are not violations of this Standard?

The standard objective needs to be modified to a feasible reliability objective such as the assessment provides a reasonably high confidence interval that the system is in a reliable state. Vague and unclear definitions will lead to significant audit discrepancies as to what appropriate measures are when it comes to implementation of operating processes/procedures.

Document Name:

Likes: 0

Dislikes: 0

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer:

Answer Comment:

Document Name:

Likes: 5
PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Long Island Power Authority, 1, Ganley Robert
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer: No

Answer Comment:

The VSL could be utilize to mitigate the compliance for R2 and other 24/7/365 requirements. The VSL for data quality could be stepped to percentage of points with bad quality, or duration. The most severe would be data quality that prevents the EMS from solving.

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Darnez Gresham On Behalf of: Thomas Mielnik, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3

Selected Answer: No

Answer Comment:

The standard objective needs to be modified to a feasible reliability objective such as the assessment provides a reasonably high confidence interval that the system is in a reliable state. Vague and unclear definitions will lead to significant audit discrepancies as to what appropriate measures are when it comes to implementation of operating processes/procedures.

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

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:

Answer Comment:

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
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
Mark Schultz	City of Green Cove Springs	FRCC	3
Chris Adkins	City of Leesburg	FRCC	3
Ginny Beigel	City of Vero Beach	FRCC	9

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC supports the comments submitted by the MRO NSRF as it relates to TOP-010-1.

The binary approach to the VSLs seems too severe. Suggest that the drafting team consider revising the VSLs to utilize moderate, high, and then severe if the entity missed one, two, three, or finally all data quality elements.

o R3 & R4: It is not clear from the wording of the single VSL level (which is Severe) if a violation of this Standard is incurred only if there are NO indications of quality of real-time data. If the meaning is to include situations where one or a few points with bad quality are missed (i.e., not notified to an operator) than assigning a Severe VSL seems inappropriate, and several levels of violations should be implemented.

o R6: Is it correct that a violation of this Standard is incurred only if there are NO indications provided to operators of poor quality of analysis results, and that missing some number of these instances is not a violation of this Standard? If the intent is to consider even a single miss a violation then assigning it a Severe VSL seems inappropriate, and several levels of violations should be implemented.

R7: Is it correct that occasional failures of the independent alarm process monitor are not violations of this Standard?

Document Name:

Likes: 1 Grand River Dam Authority, 3, Wells Jeff

Dislikes: 0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1 -

Selected Answer: No

Answer Comment:

CenterPoint Energy feels the VSLs for R1, R2, and R5 do not match the intended meaning in the language of the Requirements (implementation). It appears the focus is more on exclusion of criteria during the development phase of Operating Processes and Procedures. CenterPoint Energy feels there are developmental phases of Operating Processes and Procedures and implantation phases, and perhaps the Requirements should be separated to reflect each. In doing so, the VSLs could and should be more balanced, in both instances, from Lower VSL to Severe VSL and not so heavily weighted for documentation deficiencies.

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:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - PPL NERC Registered Affiliates - 1,3,5,6 - SERC,RFC

Group Information

Group Name: PPL NERC Registered Affiliates

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E and KU Energy, LLC	SERC	1,3,5,6
Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
Dan Wilson	LG&E and KU Energy, LLC	SERC	5
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
PPL NERC Registered Affiliates	SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas McElhinney - JEA - 1,3,5 - FRCC

Group Information

Group Name: JEA

Group Member Name	Entity	Region	Segments
Ted Hobson	JEA	FRCC	1
Garry Baker	JEA	FRCC	3
John Babik	JEA	FRCC	5

Voter Information

Voter	Segment
Thomas McElhinney	1,3,5
Entity	**Region(s)**
JEA	FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SERC,SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
John Allen	City Utilities Springfield Missouri	SPP	1,4
Darryl Boggess	Western Farmers Electric Cooperative	SPP	1,5

Donald Hargrove	Oklahoma Gas and Electric	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Robert Hirchak	CLECO	SPP	1,3,5,6
J. Scott Williams	City Utilities of Springfield Missouri	SPP	1,4
Sing Tay	Oklahom Gas and Electric	SPP	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5
Kyle McMenamin	Xcel Energy	SPP	1,3,5,6

Voter Information

Voter

Jason Smith

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

MRO,WECC,SERC,SPP

Selected Answer: No

Answer Comment:

Could it not be a lower VSL for R1 on IRO-018-1 if only one element was missing, then a medium VSL if two elements were missing, then Severe if more than two were missing?

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2

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: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jack Stamper - Clark Public Utilities - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Megan Wagner - Westar Energy - 6 -

Selected Answer: No

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: Project 2009-02

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Michael Forte	Con Edison	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1

Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
Kelly Dash	Con Edison	NPCC	3
Michael Jones	National Grid	NPCC	3
David Burke	Orange and Rockland Utilities	NPCC	3
Peter Yost	Con Edison	NPCC	4
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7

Voter Information

Voter

Ruida Shu

Segment

1,2,3,4,5,6,7

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer: No

Answer Comment:

The SDT should consider revising the VSLs to be on a graduated scale. Binary treatment of these requirements is improper and leads to higher dollar penalties for violations than are not commensurate with the risks to reliability.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment:

Comments: As the proposed requirements in IRO-018 and TOP-010 are primarily administrative in nature, ERCOT does not support the approval of VSLs that are high and severe. Administrative requirements regarding operating processes should be considered a low VSL; alarming or other indicator activity should be considered for a VSL no higher than medium.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

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: No

Answer Comment:

Refer to comments submitted for question #3.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE recommends revising the VSLs for proposed IRO-18-001, R1 and TOP-10-1, R1 and R2. Specifically, the distinction between a High VSL and a Severe VSL for each of these requirements needs clarification as to how the use of subparts establishing the various required elements that must be included within the criteria for evaluating Real-time data quality discrepancies in Parts 1.1 and 2.1, respectively, will be addressed.

The current VSLs for each of these three requirements could be read to assign only a High VSL to a registered entity that has: (1) only adopted one of the four required criteria elements in Part 1.1 (or Part 2.1 for TOP-10-1, R2) for evaluating potential Real-time data quality discrepancies; and (2) has not adopted any actions to coordinate the resolution of Real-time data quality discrepancies as required under Part 1.2 (or Part 2.2 for TOP-10-1, R2). For example, the High VSL category for TOP-10-1, R1 could potentially apply to a Registered Entity that adopts criteria for evaluating data outside of a prescribed data range, but fails to adopt similar criteria for analog data that is not updated within a predetermined time period, data entered manually to override telemetered information, data otherwise identified as invalid or suspect, as well as fails to specify any actions to coordinate the resolution of Real-time data quality discrepancies with the entity responsible for provide the data.

Texas RE suggests a better approach would be to specify that a High VSL for proposed IRO-18-001, R1 and TOP-10-1, R1 and R2 would apply to Registered Entities that have failed to adopt one or more of the required criteria in Parts 1.1 or 2.1, respectively, or have failed to adopt actions to address Real-time data discrepancies as required in Parts 1.2 or 2.2, respectively. The Severe VSL category would then be reserved for instances in which a Registered Entity has failed to (1) adopt one or more of the required criteria for evaluating Real-time data quality discrepancies and (2) adopt actions to coordinate resolution of Real-time data quality discrepancies. To use the previous example regarding the VSLs for TOP-10-1, R1, a Registered Entity that adopts criteria for evaluating data outside of a prescribed data range, but fails to adopt similar criteria for analog data that is not updated within a predetermined time period, data entered manually to override telemetered information, data otherwise identified as invalid or suspect, as well as fails to specify any actions to coordinate the resolution of Real-time data quality discrepancies would now be subject to a Severe VSL.

This approach would align the VSLs for IRO-18-001, R1 and TOP-10-1, R1 and R2 with the VSLs for other requirements in the proposed standards that do not have specifically required criteria elements. For example, under TOP-10-1, R5, the High VSL category applies to a Registered Entity if it does not establish (1) criteria for evaluating the quality of any analysis under in its Real-time assessments; or (2) actions to resolve quality deficiencies. In turn, the Severe VSL category under TOP-10-1, R5 is applicable to Registered Entity that has failed to both establish criteria for evaluating and actions to resolve quality deficiencies.

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment:

No, we ask to leave them as currently written for TOP-010-1 requirements.

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery,1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: No

Answer Comment:

Southern believes that the VRFs and VSLs for the proposed standards are too high and should be modified.

Document Name:

Likes: 0

Dislikes: 0

5. Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment: na

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment: na

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:
na

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:
na

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

AEP has chosen to vote negative on TOP-010-1, primarily driven by our concerns of a) how granular the Requirements may be regarding the data points themselves and b) the impact of R1.2 on externally provided data. As previously stated, TOP-10-1 must be written in a reasonable manner that is able to accommodate the high volume of data points which continue to increase.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

Certification requirements are the appropriate place for mandating facilities and capabilities needed to perform reliability functions. These requirements can be enforced in a similar fashion as their reliability standard counterparts without de-certifying an entity if and when requirements are violated. We urge the drafting team, NERC, the Standards Committee and the regulators to think outside of the box and not let taking the right approach be bound by existing document framework.

Document Name:

Likes: 0

Dislikes: 0

Tyson Archie - Platte River Power Authority - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer:

Answer Comment:

none

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Xcel Energy suggests that the SDT clarifies what qualifies as "independent" in TOP-010-1 R7. Can this include a separate and independent process within the same EMS system?

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer:

Answer Comment:

Suggest that the Standard Drafting team clarify that an independent alarm process monitor can be a separate and independent process within the same EMS system (R7). Therefore if an entity has a heartbeat monitor already integrated into its EMS system, the heartbeat monitor can be used. Independent doesn’t necessarily mean an independent box / system completely separate from the EMS.

Document Name:

Likes: 0

Dislikes: 0

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer:

Answer Comment:

Document Name:

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer:

Answer Comment:

This standard may establish an incentive for RC and TOP to limit the data they incorporate into the EMS since each point incorporated increases the compliance risk.

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Darnez Gresham On Behalf of: Thomas Mielnik, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3

Selected Answer:

Answer Comment:

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

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:

Answer Comment:

Duke Energy requests clarification on the use of the time horizon Same Day Operations throughout the standard. How does the drafting team envision this time horizon corresponding with Real-time monitoring and assessments?

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
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
Mark Schultz	City of Green Cove Springs	FRCC	3
Chris Adkins	City of Leesburg	FRCC	3
Ginny Beigel	City of Vero Beach	FRCC	9

Voter Information

Voter
Carol Chinn

Segment
4

Entity
Florida Municipal Power Agency

Region(s)

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

ATC supports the comments submitted by the MRO NSRF as it relates to TOP-010-1.

Suggest that the Standard Drafting team clarify that an independent alarm process monitor can be a separate and independent process within the same EMS system (R7). Therefore if an entity has a heartbeat monitor already integrated into its EMS system, the heartbeat monitor can be used. Independent doesn't necessarily mean an independent box / system completely separate from the EMS.

Document Name:

Likes: 1 Grand River Dam Authority, 3, Wells Jeff

Dislikes: 0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1 -

Selected Answer:

Answer Comment:

CenterPoint Energy has no additional 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:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Brent Ingebrigtson - PPL NERC Registered Affiliates - 1,3,5,6 - SERC,RFC

Group Information

Group Name: PPL NERC Registered Affiliates

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E and KU Energy, LLC	SERC	1,3,5,6
Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
Dan Wilson	LG&E and KU Energy, LLC	SERC	5
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6

Voter Information

Voter

Brent Ingebrigtson

Segment

1,3,5,6

Entity

PPL NERC Registered Affiliates

Region(s)

SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas McElhinney - JEA - 1,3,5 - FRCC

Group Information

Group Name: JEA

Group Member Name	Entity	Region	Segments
Ted Hobson	JEA	FRCC	1
Garry Baker	JEA	FRCC	3
John Babik	JEA	FRCC	5

Voter Information

Voter	Segment
Thomas McElhinney	1,3,5
Entity	**Region(s)**
JEA	FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SERC,SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
John Allen	City Utilities Springfield Missouri	SPP	1,4
Darryl Boggess	Western Farmers Electric Cooperative	SPP	1,5

Donald Hargrove	Oklahoma Gas and Electric	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Robert Hirchak	CLECO	SPP	1,3,5,6
J. Scott Williams	City Utilities of Springfield Missouri	SPP	1,4
Sing Tay	Oklahom Gas and Electric	SPP	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5
Kyle McMenamin	Xcel Energy	SPP	1,3,5,6

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	MRO,WECC,SERC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2

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

Jack Stamper - Clark Public Utilities - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Megan Wagner - Westar Energy - 6 -

Selected Answer:

Answer Comment:

Westar supports the comments provided by the SPP RTO.

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: Project 2009-02

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Michael Forte	Con Edison	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1

Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
Kelly Dash	Con Edison	NPCC	3
Michael Jones	National Grid	NPCC	3
David Burke	Orange and Rockland Utilities	NPCC	3
Peter Yost	Con Edison	NPCC	4
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7

Voter Information

Voter

Ruida Shu

Segment

1,2,3,4,5,6,7

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer:

Answer Comment:

Even though IRO-018-1 and TOP-010-1 are applicable to different functional entities, the contents are repetitive. It would be less cumbersome if one standard could be generated that would be applicable to all the functional entities.

Results based standards should focus on the "what" or objective opinions express by some are that the standard is overly prescriptive and could be more suited to a guideline document.

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer:

Answer Comment:

We question the SDT's practice of posting the revised SAR along with the draft standard. It is unclear if the industry is to provide feedback about the removal of "analysis" from the SAR. This appears to be a substantive change to the project's scope.

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

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Comments: ERCOT expresses concern that overly prescriptive requirements will hinder – not benefit – the processes and interactions occurring between functional entities currently as well as the continuous improvement of tools and associated capabilities. If the risk to be addressed is operator awareness of data and analysis quality issues and the taking of prompt action to resolve such issues, ERCOT recommends limited requirements that most directly address these risks. Overly prescriptive requirements that hinder tool and analyses improvement and the free-flow of functional entity communications that are already occurring do not benefit reliability. Further, the complicated nature of data exchange, inputs, and analyses require coordination and cooperation amongst many registered entities. Without a reciprocal obligation by other entities to facilitate responsiveness when an issue arises, the proposed standards and requirements will not achieve their intended objective. Until such obligation is included in the proposed standard, ERCOT is unable to support its approval. This reciprocal obligation is critical for achieving the implied objective of the proposed standard because – even where a Reliability Coordinator initiates resolution of issues quickly – lack of responsiveness by the entity that is situated to address an issue will prevent effective, efficient resolution.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

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:

Answer Comment:

Overall, ITC supports the intent of the standard which is to ensure that quality of Real-time Assessment is adequate to maintain BES reliability. However, the assessment of Real-time data and Real-time Assessment quality is a function better performed offline using larger sets of historical data to identify systematic issues, monitor performance trends of Real-time Assessment, and implement corrective actions. The proposed standard as written can be interpreted that System Operators should monitor and address all data and Real-time Assessment quality issues in Real-time which may be distracting to the Operator. In addition, the term ‘quality’ is very subjective and can lead to different interpretations by different TOPs and regional entities making it difficult to prove and assess compliance.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE recommends reviewing references in the Evidence Retention section of TOP-010-1. There is reference to R5 and R6 having a rolling 30 day period for evidence. It would seem that is an incorrect reference as R5 requires implementation of a Process or Procedure. The 30-day period is short of a timeframe and is not supported by industry practice. Similar statement for IRO-018-1 except it references R3 and R4. R3 is a requirement to implement a procedure. The SDT may have been trying to capture the quality of data indication requirements in each of the Standards.

In TOP-010-1, why is the data retention for a BA different from that for a TOP (relates to the incorrect reference but if the reference is corrected this issue goes away)?

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

In our opinion, clarity is needed throughout the proposed standards so that entities will not be confused over how the requirements will be audited.

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery,1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Marsha Morgan

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Comments of the Foundation for Resilient Societies, Inc. on NERC Project 2009-2, Draft NERC Standard IRO-018-1, "Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities."

Submitted to NERC on November 9, 2015

The Foundation for Resilient Societies, Inc. supports "reliability standards" that are designed to improve the reliability of the bulk electric system. We supported the near-real-time monitoring initiative for critical equipment, "Project 2012-01 Equipment Monitoring and Diagnostic Devices." Unfortunately, the NERC Standards Committee moved to cancel this project at their June 5, 2013 meeting and this cancellation was later approved by the NERC Board of Trustees. During the period when no NERC monitoring project was in process, Generator Operators used the potential lack of "visibility" during solar geomagnetic disturbances (GMD) to seek and obtain exemption from NERC Standard EOP-010-1 — Geomagnetic Disturbance Operations. This imprudent exemption increased risks to large power transformers in the bulk power system.

The present revival of a NERC real-time monitoring standard has potential to improve equipment monitoring and system reliability. But the lack of metrics or boundary conditions for equipment or events requiring real-time monitoring undermines the prospective benefits of this proposed standard. Without metrics, how can measures such as "dated operator or supporting logs, dated checklists, voice recordings (or other evidence)" be evaluated?

There are no connections between these processes and/or procedures for monitoring reliability or performing analysis, on the one hand, and cybersecurity standards, on the other hand. The latter critically affects reliability. How are these interrelationships to be considered?

The term "quality" as used 23 times in the standard is a very general term. Its composition is affected by hundreds of factors in instrumentation, pre-Reliability Coordinator processing, etc. Can reliability even be determined in the absence of a grid-wide standard for data flows?

The rationale for R3 and R4 asserts that "operators have procedures and receive indication(s) to address issues related to the quality of the analysis inputs used for Real-time Assessments." How can such a vague process be judged compliant or non-compliant? The measurement examples cited in M2, "computer printouts" (of what?) and system specifications (what "systems"?), are so non-deterministic as to be meaningless in judging quality of analysis.

Compliance would be nearly non-enforceable for these vague reliability monitoring and analytic assessments. How is NERC planning on enforcing compliance particularly when most Reliability Coordinators (RC) are also the Regional Entity? In almost every case, the RC has no evidence to support compliance with these unmeasurable, metric-less requirements as prescribed in this set of standards.

Significantly, the draft standard does not require monitoring of critical equipment such as large power transformers, generators, or reactive power support devices. Instead, the standard takes the approach of requiring monitoring of the "quality" of whatever data flows might exist. A good way to minimize compliance costs with this standard would be to simply eliminate data flows from critical equipment.

Overall, the Standard Drafting Team needs to be more specific and more rigorous. Otherwise, a vague standard will leave the false impression that real-time monitoring requirements exist; whereas, in reality, the standard will provide an escape hatch for equipment monitoring requirements, resulting in net harm to reliability of the bulk power system.

Submitted by

Wm. R. Harris

William R. Harris, Secretary, for the

FOUNDATION FOR RESILIENT SOCIETIES, INC.
52 Technology Way, Suite 4E1
Nashua, N.H. 03060

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2009-02 Real-time Monitoring and Analysis Capabilities
IRO-018-1 and TOP-010-1

DO NOT use this form for submitting comments. Use the electronic form to submit comments on IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities and TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities. The electronic comment form must be completed by **8 p.m. Eastern, Monday, November 9, 2015**.

Documents and information about this project are available on the project page. If you have any questions, contact Standards Developer, Mark Olson (via email), or at (404) 446-9760.

Background Information

Project 2009-02 Real-time Monitoring and Analysis Capabilities originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). The project SAR was revised earlier this year to account for proposed revisions to TOP and IRO standards developed in Project 2014-03 that are pending regulatory approval. Project 2009-02 is developing requirements to address monitoring and analysis capability issues identified in the 2008 RTBPTF report and the 2011 Southwest Outage Report, as well as addressing FERC Order No. 693 directives.

The Standard Drafting Team (SDT) developed two proposed Reliability Standards to meet the objectives outlined in the project SAR. IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities addresses issues related to the quality and availability of Reliability Coordinator (RC) monitoring and analysis capabilities. TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities contains similar proposed requirements for Transmission Operators (TOPs) and Balancing Authorities (BAs).

Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. The SDT has proposed a new standard IRO-018-1 to address RC monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

x No
Comments: Southern believes that the criteria in R1.1 should be limited to the RC's ability to monitor and assess the current/expected condition of its RC area within the capabilities of its monitoring tools not including the criteria listed in R1.1.1-R1.1.4.

Each RC has the inherent responsibility to protect the integrity of the system in its RC area and contribute to the overall integrity of Interconnection as required by other approved reliability standards. Other approved standards require the RC to have monitoring tools and capabilities to assess system conditions in its area and to perform next day and real time reliability assessments to identify/mitigate potential issues that could have an adverse impact on reliability.

In order to fulfill its responsibility, the RC performs monitoring through the information collected from the modeled facilities in its RC area to accurately assess the state of the system and to perform real time assessments. Throughout this process, the RC is constantly evaluating the quality of data received to ensure it has an accurate state of system conditions to perform real time assessments. To impose a new standard focusing on data quality would only serve as administrative in nature and would not provide any substantial increases in reliability.

2. The SDT has proposed a new standard TOP-010-1 to address TOP and BA monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

x No

Comments: Southern believes that the criteria in R1.1 should be limited to the BA/TOP's ability to monitor and assess the current/expected condition of its BA/TOP area within the capabilities of its monitoring tools not including the criteria listed in R1.1.1-R1.1.4.

Each BA/TOP has the inherent responsibility to protect the integrity of the system in its BA/TOP area and to not contribute or cause any system violations in adjacent BA/TOP areas as required by other approved reliability standards. These already approved standards require the BA/TOP to continuously monitor the modeled facilities in its BA/TOP area and to accurately assess the state of the system using the information collected.

The BA/TOP is constantly evaluating the quality of data received to ensure it has an accurate state of system conditions to perform real time assessments. To impose a new standard focusing on data quality would only serve as administrative in nature and would not provide any substantial increases in reliability.

3. Do you agree with the Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

X No

Comments: Southern believes that the implementation date should be pushed back to allow time for the industry to determine the appropriate technology that is sufficient for each entity's operations. We also believe that in order to fully comply with the proposed standard, enough time should be allowed for the industry to update their current procedures and/or to create acceptable procedures, provide training to the appropriate System Operators and allow sufficient time for the entities to determine the technology available that is available and appropriate to support their operations, along with the required functionality.

4. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

X No

Comments: Southern believes that the VRFs and VSLs for the proposed standards are too high and should be modified.

5. Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.
Comments:

Consideration of Comments

Project Name: 2009-02 Real-time Monitoring and Analysis Capabilities | IRO-018-1 & TOP-010-1

Comment Period Start Date: 9/24/2015

Comment Period End Date: 11/9/2015

Associated Ballots: 2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 IN 1 ST

2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 Non-binding Poll IN 1 NB

2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 IN 1 ST

2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 Non-binding Poll IN 1 NB

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has not been included, 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 Project 2009-02 Standards Drafting Team (SDT) appreciates the careful review and constructive feedback from stakeholders. As a result of comments received, the SDT made many improvements to the standards and implementation plan to incorporate stakeholder recommendations. Although Section 4.12 of the NERC Standard Processes Manual indicates that the SDT is not required to respond in writing to comments from the previous posting when it has identified the need to make significant changes to the standard, the SDT is providing summary responses to the comments received in order to facilitate stakeholder understanding of the changes made for the second posting.

The following is an overview of changes made by the SDT. Specific comments and revisions are discussed more fully in the summary consideration that follows.

- **Operating Procedures for Real-time data quality.** The SDT removed requirement parts that were unnecessarily prescriptive and clarified the scope of required actions to resolve Real-time data quality issues.
- **Operator awareness of Real-time data and analysis quality.** Stand-alone requirements to provide indications of Real-time data quality and analysis quality to System Operators were removed. The reliability objectives are to be addressed within the applicable entity's Operating Procedures.
- **Operating Procedures for analysis quality.** The SDT clarified the scope of the required actions to resolve analysis quality issues affecting the applicable entity's Real-time Assessments.
- **Alarm process monitoring.** The SDT revised the requirement for clarity.
- **Violation Severity Levels (VSLs).** The SDT revised the VSLs and fully incorporated degrees for assessing non-compliance with the requirements.
- **Implementation Plan.** The proposed Implementation Plan was revised such that all requirements become effective 18 months following regulatory approval.
- The SDT added a Guidelines and Technical Basis section with expanded details from the rationale boxes to clarify the SDT's intent.
- Requirement time horizons were revised.

Questions

1. The SDT has proposed a new standard IRO-018-1 to address RC monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

2. The SDT has proposed a new standard TOP-010-1 to address TOP and BA monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

3. Do you agree with the Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

4. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not **agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.**

5. Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.

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 SDT has proposed a new standard IRO-018-1 to address RC monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

Summary Consideration

Operating Procedures for Real-time data quality. The SDT removed requirement parts that were unnecessarily prescriptive, and clarified the scope of required actions to resolve Real-time data quality issues. In response to issues and concerns from stakeholders explained below, proposed IRO-018-1 Requirement R1 was revised as follows:

R1. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: [Violation Risk Factor: Medium] [Time Horizon: ~~Same Day Operations,~~ Real-time Operations]

1.1. Criteria for evaluating ~~potential~~ the quality of Real-time data; ~~quality discrepancies including, but not limited to:~~

~~1.1.1. Data outside of a prescribed data range;~~

~~1.1.2. Analog data not updated within a predetermined time period;~~

~~1.1.3. Data entered manually to override telemetered information; and~~

~~1.1.4. Data otherwise identified as invalid or suspect.~~

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to ~~coordinate resolution~~ resolve ~~of~~ Real-time data quality issues ~~discrepancies~~ with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

Specific comments and SDT responses are provided below:

- **Some commenters indicated that the proposed Requirement R1 was overly prescriptive or required entities to have criteria for evaluating Real-time data quality that may not apply to all systems used in Real-time monitoring.** The SDT revised this requirement in both of the proposed standards to align with the SDT's intent. The example list of criteria that needs to be addressed in the Operating Procedure or Operating Process has been moved to the guidelines and technical basis section, and the list clearly indicates that only the applicable criteria need to be included.
- **Other commenters suggested including additional details, metrics, or boundary conditions for equipment or events in the proposed standard to establish criteria for data quality.** The SDT considered alternate requirements/parts to specify data quality within the standard and determined that the best approach for reliability was for applicable entities to determine criteria for evaluating data quality in its Operating Procedures or Operating Processes. This is the approach taken with the

proposed standard. The SDT does not believe that there is a 'one size fits all' metric for data quality as part of a continent-wide standard requirement. The SDT believes that the data quality issue is best decided on a case-by-case basis using sound professional judgment and described in the applicable entity's Operating Procedure or Operating Process.

- **Commenters stated that the some data quality issues were beyond the direct control of the applicable entity. Commenters also proposed adding requirements to compel entities providing bad data to take corrective action.** The proposed standard requires entities to have an Operating Procedure or Operating Process to address the quality of Real-time data necessary to perform Real-time monitoring and Real-time Assessments. Entities have flexibility for determining the appropriate approach for evaluating the quality of their Real-time data, and for determining how to resolve Real-time data quality issues affecting Real-time assessments. The SDT believes an Operating Procedure or Operating Process can be developed to address data quality issues, even if they are beyond the direct control of the applicable entity. To satisfy the intent of the requirement, Part 1.3 requires that actions be taken to resolve data quality issues with the appropriate entities responsible for the data. The SDT does not believe additional requirements in proposed IRO-018-1 are necessary. IRO-010-1a and IRO-010-2 data specification standard establish obligations for entities to provide data and information to the Reliability Coordinator.
- **A commenter was concerned that the scope of data to be addressed was too broad.** The SDT modified the requirement (now Part 1.3) and provided a clear description of the SDT's intent in the Guidelines and Technical Basis Section. Requirement R1 Part 1.3 specifies the RC shall include actions to resolve Real-time data quality issues when its Real-time Assessments are affected. The Operating Procedure or Process should clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to resolve data quality issues in an appropriate timeframe.

Operator awareness of Real-time data and analysis quality. Stand-alone requirements to provide indications of Real-time data quality and analysis quality to System Operators were removed (Requirements R2 and R4, respectively, in initial draft standard). The reliability objectives are to be addressed within the applicable entity's Operating Procedures or Operating Processes. Specific comments are below, along with SDT responses:

- **Some commenters suggested combining requirements for Operating Procedures with requirements to provide notifications to operators.** The SDT removed the stand-alone requirement to provide indications of Real-time data and analysis quality and incorporated the objective in requirements for Operating Procedures.
- **Commenters were concerned that the proposed requirement to provide System Operators with indications of data or analysis quality could potentially detract from operator situational awareness, or that evidence of compliance with the proposed requirement for each data point was burdensome.** In the proposed revised standard, entities are required to

include provisions for indicating data quality in their Operating Procedures. Provisions could include descriptions of quality indicators that are currently in use, such as display color codes, data quality flags, or other such indicators used by operating personnel as found in Real-time monitoring specifications. This approach provides entities with flexibility to determine how to achieve the reliability objective of providing operators with indications of data quality within the capabilities of existing Real-time monitoring and Real-time Assessment systems. The SDT is not implying that an entity would or should overload the operator with alarm indications of every instance of data quality issues. The SDT believes that the data quality issue is best decided on a case-by-case basis using sound professional judgment and described in the applicable entity's Operating Procedure or Operating Process.

Operating Procedures to address the quality of analysis used in Real-time Assessments. The SDT clarified the scope of actions to resolve analysis quality issues required to be included in an entities Operating Procedure or Operating Process, and added clarifying details to the rationale and Guidelines and Technical Basis section of the proposed standard. Proposed Requirement R2 is revised as follows:

~~R3.~~R2. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to ~~maintain~~ address the quality of ~~any~~ analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: [Violation Risk Factor: Medium] [Time Horizon: ~~Same Day Operations,~~ Real-time Operations]

2.1. Criteria for evaluating the quality of ~~any~~ analysis used in its Real-time Assessments; and

~~3.1.~~2.2. Provisions to indicate the quality of ~~any~~ analysis used in its Real-time Assessments; and

~~3.2.~~2.3. Actions to resolve analysis quality issues affecting its Real-time Assessments ~~deficiencies in any analysis used in its Real-time Assessments~~.

Specific comments and SDT responses are provided below:

- **Commenters asked for clarification on what the SDT meant by *any analysis used in Real-time Assessments.*** Analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis, or other studies used for Real-time Assessments. Some entities may use several types of analysis in performing a Real-time Assessment. The Operating Procedure must address the quality of these analysis inputs to Real-time Assessments.
- **Commenters indicated the wording of the proposed requirement was unclear or overly broad.** The SDT revised the requirement by replacing *maintain* with *address*. An Operating Procedure addresses the quality of analysis used in Real-time Assessments by containing: 1) criteria for evaluating quality; 2) provisions to indicate quality to operating personnel; and 3) actions to resolve analysis quality issues affecting Real-time Assessment. The proposed requirement provides entities with flexibility to establish criteria for evaluating quality, accounting for system characteristics, Real-time Assessment approach,

and the capabilities of their Real-time tools. The SDT added a non-exclusive list of sources of quality criteria in the guidelines and technical basis section of the standard: "*The entity must use appropriate quality criteria based on the analysis capabilities used to perform Real-Time Assessments, such as solution tolerances, mismatches with Real-time data, convergences, etc.*"

- **A commenter was concerned that requirement part (2.3) wording was overly broad and implied that action was required to resolve every analysis quality deficiency.** The SDT modified the requirement (now Part 2.3) to clarify that the Operating Procedure must include actions to resolve analysis quality issues that affect its Real-time Assessments.
- **A commenter recommended increasing the evidence retention period for this requirement from 30-days.** The evidence retention period is aligned with the evidence retention period for performing Real-time Assessments contained in IRO-008-1 Requirement R2 and IRO-008-2 Requirement R4, which is a rolling 30-day window.

Independent Alarm Process Monitoring. Several commenters sought clarification regarding what is meant by an independent alarm process monitor. The SDT revised the requirement and rationale box to clarify the intent as shown below.

Rationale for Requirement R4: *The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.*

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term independent. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

R4. Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

- **Some commenters asked if the independent alarm processor needed to be separate from the EMS system.** The proposed requirement does not preclude use of the EMS system as an independent alarm process monitor.

Time Horizons. A commenter questioned the *same-day operations* time horizon. The SDT agrees that all requirements should be satisfied in Real-time and has removed same-day operations.

Commenters questioned the need for reliability standards to address these issues and suggested that the reliability objectives would be better achieved through Organization Certification program. The proposed requirements in IRO-018-1 and TOP-010-1 address outstanding regulatory directives from Order No. 693 and various industry recommendations as described in the SAR.

Although this project was paused in 2011, it received renewed focus in 2013 when FERC identified shortcomings in previously proposed TOP and IRO standards (See FERC Notice of Proposed Remand issued Nov 21, 2013). Project 2014-03 - Revisions to TOP and IRO Standards was initiated to address issues identified in FERC's November 2013 NOPR, however the Project 2014-03 SDT, NERC Staff, and FERC Staff agreed that Real-time Monitoring and Analysis capabilities would not be completely addressed within the project. Accordingly, the Standards Committee authorized resumption of Project 2009-02 in 2015 following NERC's filing of TOP and IRO standards from Project 2014-03. The SDT's experience and the ongoing efforts to improve Real-time situational awareness within the industry indicate that issues of data quality and Real-time analysis quality remain relevant reliability objectives. The proposed standards address these in a manner that provides flexibility for applicable entities to account for system needs and Real-time monitoring and analysis capabilities. Furthermore, addressing these reliability issues through standards ensures ongoing accountability that begins with organization certification and is maintained through day-to-day operations.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:	Our comments on the SAR posting essentially disagreed with the creation of this standard and the TOP-010 standard to mandate monitoring and analysis capability for the RC and TOP, which are the fundamental “bread and butter” capabilities that these entities must have to perform their assigned functions. We further suggested that the FERC directive could be met by an alternative but more appropriate means of incorporating the necessary requirements in the Organization Certification Requirements. The SDT disagree with our proposal citing that: “…. these capabilities should be demonstrated at the organization certification stage, but believes they should also be maintained on an ongoing basis through adherence to standards. Furthermore, development of standards is appropriate since, in general, organization certifications are based on the body of approved standards.” We continue to respectfully disagree that “maintained on an ongoing basis through adherence to standards” is the only approach. Such maintenance can also be mandated through the certification process. For example, if basic monitoring capability is required for certification, there needs to be periodic assessment of whether or not such capability continues to exist at a level to be specified, or no lower than that assessed at the initial certification stage. To argue that the only way to ensure maintenance through adherence to standards, then a good part of the current certification requirements will have to become standards or whose quality or functional capability need to be ascertained through standards. This is not the case today, nor do we think this is the case in the future. We once again urge the standard drafting team to consider the organization certification alternative as a means to address this FERC directive. For so long as the directive is met, it should not matter whether the requirements are incorporated into the certification requirements or in a new standard. Putting them into certification requirement is consistent with the intended use of

organization certification process to ensure the responsible entities have the capability to fulfill their functional obligations; whereas putting them into reliability standards is inconsistent with the intended use of standards to drive the right planning and operation behaviors.

Notwithstanding the above disagreement with creating this and the TOP-010 standards, the currently posted draft standard appears to be micro-managing the requirements and process for providing adequate tool/capability.

The 5 requirements in the proposed IRO—018 standard essentially require that the RC:

- Implement an Operating Process or Operating Procedure to address the quality of the Real-time data;

· Indicate to the operating personnel the quality of the Real-time data

· Implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments

· Provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments

· Utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

These requirements mandate the “how”, not the “what”, and are overly prescriptive and micro-managing the daily business of the RC. If the SDT decides to keep using a standard to meet the FERC directive, then the standard needs only to be one requirement that mandates the RC having in place acceptable quality monitoring and analysis capability at all times

	(except the down time for repair but for which a backup needs to be in place) for the RC to perform its functions and meet all applicable reliability standard. This requirement will be the "what", i.e., the necessary capability to perform the RC functions with specific reliability outcome - to ensure reliability. In brief, we are unable to support this standard for two main reasons: (a) that the standard is more suited for inclusion in the Organization Certification Requirements and (b) the standard as currently drafted is overly prescriptive and micro-managing.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer:	No
Answer Comment:	We would like to see "quality" defined or clarrified. Also, we are not sure who is responsible for the quality of the data received from the interconnections. We also support some of the comments coming out of the MRO standards group.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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: No

Answer Comment:	The NSRF has concerns with redundancy and technical complications with the IRO-018-1 standard as proposed. The data quality objective can be simplified into a single requirement IRO-018-1 or TOP-001-3 / IRO-008 which is for entities to have tools or processes that consider data quality to reasonably assure a reasonably high confidence that the system is in a reliable state. Existing Energy Management Systems (EMS) / Real-Time Contingency Analysis (RTCA) tools already have this capability. **Redundancy:** The NSRF recognizes that FERC directed the drafting team to address missing data quality issues based on the 2003 blackout report. However, existing standards TOP-001-3 and TOP-003-3 already require effective monitoring and control which includes proper data. As an example, R13 of TOP-001-3 sets clear requirements that a real-time assessment must be performed at least once every 30 minutes. All TOPs assessment tools already consider bad data detection and identification from embedded software algorithms which are pre-requisites for successful execution of SE/RTCA. TOP's engaged in monitoring the execution of their assessment tool(s) already address problems with data input quality and assessment quality. Assessment tools must have robust data quality input and assessment capabilities to detect and identify problem(s) with any single piece of data (out of thousands of inputs) especially if that particular bad input (or limited set of bad input data) did NOT affect overall successful performance of the tool. **Technical Compliance Complications that Distort the Reliability Goal:**

	The zero defect nature of compliance, until fixed, drives unnecessary costly EMS / RTCA system upgrades without measureable system reliability improvements. The proposed TOP-010 and IRO-018 standards introduce vague and unclear formulations that will cause misunderstandings during compliance audits. Therefore, it is better to revise TOP-010 to a single requirement or revise TOP-001-3 or TOP-003-3 (and the corresponding IRO standards) with an additional simple requirement for entities to have tools or processes that considers data quality to reasonably assure a high confidence that the system is in a reliable state. Assessment tools use thousands of input data points including analog measurements and switching device statuses. Therefore, the reliability goal(s) are that the assessment tool has bad data detection and identification algorithms that allow the assessment tool to solve, and notify / log the system operator of bad data, and alarm if the bad data may compromise the assessment or solution. Identifying vague input data issues such as “analog data not updated” or “data identified as suspect” is problematic from a compliance standpoint. Some Energy management Systems (EMS) simply do cannot identify all suspect data and therefore the zero defect compliance expectation to identify all suspect data or all bad analog data is technically infeasible. The reliability goal is a high confidence assessment that the system is in a reliable state. That is very different from the stated compliance zero defect standard as written to identify all “analog data not updated” or identify “all suspect data”. Significant technical problems exist with the TOP-010 requirements when applied to input data received from other TOPs or RC’s (either directly or via ICCP). There are no technically feasible mechanisms to detect for “manually entered statuses. An example is detecting a manually entered “CLOSED” circuit breaker status whose actual status is “OPEN”, if such data was received via ICCP.

TOP-010 R3 is unclearly defined as Transmission Operators would have major difficulty in coming up with a conclusion as to what is “the quality of data necessary to perform real-time assessment”. At any moment in time, any specific measurement (or subset of measurements) might either be lost or be detected as “bad”. That does not necessarily mean that the real-time assessment would be inaccurate or invalid. The tool’s accuracy can be measured by other inherent quantitative indicators such as algebraic sum of allocation errors” or “confidence percentile”. An aggregate reasonable confidence percentile measurement would be a sufficient system reliability objective reasonably proving the system was in a reliable state.

TOP-010 R5 introduces unclear terminology of “maintaining the quality of any analysis used in real-time assessment”.

Likes:	1	Grand River Dam Authority, 3, Wells Jeff
Dislikes:	1	Porter Tammy On Behalf of: Rod Kinard, Oncor Electric Delivery, 1,

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer: No

Answer Comment:		RC, BA & TOP entities currently have adequate tools for real-time monitoring and analysis. The existing Standards adequately define what needs to be monitored by each entity without defining the tools. Creating new requirements will not increase the reliability of the BES. Additionally, some of the new proposed requirements (IRO-018-1 Req. 1, TOP-010-1 Req. 1) state: Each RC/TOP/BA shall implement and Operating Process to address the *quality* of the Real-time data… the term *quality* is ambiguous and subjective. This term needs to be defined. Similar to Requirement 2, the terms *indications of quality* needs to be defined. If not defined, it could result in varying interpretations throughout the industry. Lastly, the NERC Operating Reliability Subcommittee (ORS) has drafted a Reliability Guideline, "Loss of Real-Time Reliability Tools Capability / Loss of Equipment Significantly Affecting ICCP Data." This guideline will help ensure that tools are adequate and if they are degraded for any reason, the potentially impacted entities are aware and can take action if needed. PJM supports the comments submitted by the ISO/RTO Council Standards Review Committee.
Likes:	5	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph Long Island Power Authority, 1, Ganley Robert PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer: No

Answer Comment: R1.1 uses “but not limited to”. That language is too open ended and cannot be audited or compliance limited. Compare it to R3. ‘ But not Limited to” only belongs in a Measurement.

R2 is a ambiguous in whether a single data point of bad quality needs to be flagged or if the aggregate data is so bad that state estimator can’t solve. Modern EMS systems incorporate data quality checks within their algorithms. However, how this requirement is phrased will dramatically impact the compliance risk an organization faces.

Darnez Gresham - Darnez Gresham On Behalf of: Thomas Mielnik, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3

Selected Answer: Yes

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

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: No

Answer Comment: R3 & R4: Duke Energy requests further clarification on the compliance aspects of R3 and R4. Operating studies use the latest information available, but that data changes continuously so the studies will never be 100% accurate. More information is necessary to know how to measure their quality effectively.

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
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

Mark Schultz	City of Green Cove Springs	FRCC	3
Chris Adkins	City of Leesburg	FRCC	3
Ginny Beigel	City of Vero Beach	FRCC	9

Selected Answer: No

Answer Comment: In part 1.1 of R1, if the bulleted list is intended to be an example list, then the examples should not be given part numbers but should be rolled up into the main sentence. If it is intended to be a minimum set of criteria, then "but not limited to" should be replaced with "at a minimum".

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1 -

Selected Answer: No

Answer Comment: See comments for Q2.

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

While Peak supports the spirit of this proposed Standard, Peak recommends there be a requirement for entities who provide data per IRO-010 to resolve data quality issues in a mutually agreeable time schedule. The RC could have a process, but if there is no requirement for entities to fix the issues the end result is not achieved. The Standard as written falls short of providing resolution. The same comments apply to TOP-010-1.

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SERC,SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
John Allen	City Utilities Springfield Missouri	SPP	1,4
Darryl Boggess	Western Farmers Electric Cooperative	SPP	1,5
Donald Hargrove	Oklahoma Gas and Electric	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Robert Hirchak	CLECO	SPP	1,3,5,6
J. Scott Williams	City Utilities of Springfield Missouri	SPP	1,4
Sing Tay	Oklahom Gas and Electric	SPP	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5
Kyle McMenamin	Xcel Energy	SPP	1,3,5,6

Selected Answer: No

Answer Comment:

We do not believe the issues addressed by the FERC directive rise to the level of requiring a reliability standard. The intent of the directive and the resulting actions to be taken by the various entities would be better served by an official Guideline rather than a generic standard. Forcing this into a Standard requires a one-size fits all approach that is leading to varied interpretations on “quality” and “adequacy” and may not enhance reliability of the BES.

We believe the requirements in general could be improved to be more results based. As written, they largely will only result in identifying deficiencies after the fact when doing event analysis. An entity may have a process or procedure as required, but they could miss a piece of data or fail to identify fully the impact a quality issue may have upon their situational awareness. Simply having the process does not result in increased reliability.

Most entities already have a process in place to alarm or indicate data quality as needed to maintain reliability. Entities are already required to operate reliably, within SOLs and IROLs, etc. The creation of this standard as written would serve only to document that process and put it under auditable enforcement – with no discernible impact to maintaining reliability. In order to make this standard truly results based, there needs to be some identification of the quality level, or data quality thresholds that must be maintained in order for reliability to be maintained. Then that level (or quality of the data measurements) must be maintained per the standard.

We suggest that there needs to be more direction given by the Standard in a few areas. One is that the applicable entity should be determining a data range, time periods, number of manually entered values, etc. that can degrade analysis to the point reliability is threatened (R1.1.1-R1.1.4).

We also find it problematic when an entity may not “own” the data and is simply receiving a quality flag from a sender. The RC for example may not receive an accurate quality flag or the quality flag is corrupted in translation over ICCP. Also, there is no requirement that the measurement devices even be of a particular accuracy. For example the quality threshold may be more narrow than the accuracy of the device.

The use of the term “suspect” in R2.1.4 in TOP-010-1 could lead to an interpretation that the operator “should have suspected” the data was incorrect. The word “suspect” is used in some EMS packages as an identifier for garbage or data that is suspect. We recommend the word be evaluated and replaced.

R3 is very problematic in that it infers there is a level of in-adequacy that studies must not fall below when requiring a level of “quality” to be maintained. This seems to be an attempt to not use the word “adequate”. Without defining the required level of quality, there is no way an entity can be compliant. Any entity may experience some reduced level of quality, but may still have acceptable performance from their studies without taking action to correct or mitigate the data. As written, the entity would be in violation for simply failing to “maintain” the level of quality. Perhaps R3 could be written this way:

R3. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to maintain an acceptable level of quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

3.1. Criteria for determining the minimum quality of any analysis used in its Real-time Assessments; and

3.2. Actions to resolve unacceptable quality deficiencies in any analysis used in its Real-time Assessments.

	R4 seems to be applicable to situations where a tool is used to perform the RTA. This can become problematic when the assessment is simply an evaluation done by reviewing data and determining that no changes on the system have occurred such as could occur with a TOP who has only a few BES elements and does not possess an EMS or RTCA style "tool". We suggest that altering the phrase "independent alarm process monitor" could be beneficial. As stated, the phrasing seems to suggest particular processes or tools rather than the intent to just have an "independent process" to monitor the alarming system. We suggest the change as: **R5.** Each Reliability Coordinator shall utilize a process to independently monitor its Real-time monitoring alarm process monitor in order to provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer:	No

Answer Comment:	The SRC fails to see the reliability risk that this project is intending to address. The August 14 Blackout as well as the 2011 Southwest Outage have thoroughly and exhaustively investigated, reported upon, and the root causes mitigated appropriately. Therefore, pointing to the need for this project based on mitigated, historical events falls short of identifying the reliability risk that this is intended to "fix." If, for example, WECC continues to have a vested interest in further mitigating the 2011 Southwest Outage though standard development, we suggest this project be migrated into a regional standard for WECC. Lastly, the SRC believes that, absent a Standard specific for tools, a RC, TOP, or BA would, in fact, have violations of existing operational Requirements if they do not provide adequate monitoring and tools to their operators (i.e. other "things" would happen). Further, the Requirements as written, "…to address the quality of the Real-time data necessary…" are ambiguous, lack consensus about how to measure, and do not rise to the level of a NERC Standard. This proposed project appears to be well-suited for a guideline document as opposed to a Standard. As written, the SAR appears to intend to write a "how" not "what" Standard (*i.e.*, it does not appear to be a results-based standard). The SRC believes that the existing Standards (*i.e.*, IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (*i.e.*, without defining the "how"), which is appropriate. In the alternative, this could be considered a process to be used for Certifying new entities, in line with a methodology developed by the ERO and registered entities for assessing adequacy of tools for addressing the "quality" of real-time data, for assurance that RC, BA and TOPs have the ability to monitor appropriately in accordance with existing, performance-based Standards Requirements. The SRC notes that the tools available to operators have progressed well beyond those available in 2003. If defined tools would have been hardcoded

in a standard at that time, it would have limited focus and investment to those things that were in the standard. Further, expanding on our point above, the SRC believes that the "what" regarding tools is more appropriately captured in the certification expectations for BAs, RCs, and TOPs. Additionally, it would be appropriate for Regions to evaluate tools as part of the Registered Entity's Inherent Risk Assessment (IRA). This would include the scope of tools, backups, etc. and would provide an adaptable approach that would encourage continuous improvement.

Additionally, the SRC recommends that NERC coordinate with the NATF to encourage inclusion of an ongoing "care and feeding" of tools evaluation and information sharing in their efforts with the provision that they make information on good practices available to the wider NERC community so that non-members can learn from the innovation of others.

Finally, to avoid these issues in the future and to support communicating to FERC when a Standard is not needed and another tool is more suitable, the SRC suggests that future SARs be voted on by industry to determine whether they should proceed as a Standards project or another means is a more appropriate method through which to achieve the SAR's objective.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment: Not applicable tp BPA

Jack Stamper - Clark Public Utilities - 3 -

Selected Answer: No

Answer Comment: See comments in item 2 below.

Megan Wagner - Westar Energy - 6 -

Selected Answer: No

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: Project 2009-02

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Michael Forte	Con Edison	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
Kelly Dash	Con Edison	NPCC	3
Michael Jones	National Grid	NPCC	3
David Burke	Orange and Rockland Utilities	NPCC	3

Peter Yost	Con Edison	NPCC	4
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7

Selected Answer: No

Answer Comment:

By Part 1.1 stating “Criteria for evaluating potential Real-time data quality discrepancies…” implies that a contingency analysis has to be done. Suggest removing “potential” from Part 1.1.

Language in R1.1 uses “but not limited to”. That language is too open ended and cannot be audited. Compare it to R3 use of “shall include”. “But not limited to” only belongs in a Measurement.

R2 is a bit ambiguous in whether a single data point of bad quality needs to be flagged or if the aggregate data is so bad that the state estimator can’t solve.

Suggest replacing the word “any” from R3 and R4 (relative to “any analysis”) and replacing with “reliability related” as “any” could be too broadly applied or interpreted. Additionally, the term analysis is broad. Standards related to Project 2014-03, approved through NERC as of this time, define such things as Real Time Assessments and Operational Planning Analysis. It’s not exactly clear what analysis would be referring to.

Glenn Pressler - CPS Energy - 1 -

Selected Answer: No

Answer Comment: Need more clarity in general; see Q2 for more specifics.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5

Selected Answer: No

Answer Comment:	(1) The language within Requirement R1 is vague and should not require criteria for evaluating data quality. References to criteria for evaluating data quality should not be ambiguous and unenforceable. The requirement needs to identify what real-time data is necessary to perform monitoring and assessments and consider if the data specifications maintained for reliability. The SDT should also clarify what is considered "quality" data and how an entity should identify data quality. The minimum criteria is not specific and does not provide enough information to make an objective determination. (2) Requirement R4 provides indications that the drafting team expects System Operators to receive quality data. If an entity makes data available with a quality code, but the system fails to update the quality code, is this a violation? The SDT also needs to identify the evidence required for this requirement and if a validation process is necessary. (3) The language within Requirement R5 expects an entity to have redundant alarms or independent alarms for real-time monitoring. What does "independent" mean in this context? The drafting team provides technical examples such as "heartbeat" or "watchdog" monitoring systems in its rationale, but does the independent system need to be separate from the real-time monitoring?

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:	No

Answer Comment:	ReliabilityFirst offers the following comments for consideration: 1. Requirement R2 i. It is unclear as to what the phrase “indication(s) of the quality of the Real-time data” is referring to. RF requests clarification on the term “indications” and what this involves. i. Also, since the System Operators work for the RC, it is unclear whom at the RC will be providing “indications” to the System Operators. As written, the System Operators (working for the RC) could provide indications to themselves. This does not seem to be the intent of the Requirement. 2. Requirement R4 i. Similar to Requirement R1, it is unclear as to what the phrase “indication(s) of the quality of any analysis” is referring to. RF requests clarification on the term “indications” and what this involves. i. Also, since the System Operators work for the RC, it is unclear whom at the RC will be providing “indications” to the System Operators. As written, the System Operators (working for the RC) could provide indications to themselves. This does not seem to be the intent of the Requirement.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:	No

Answer Comment:	Comments: ERCOT expresses its concern that the proposed standard is too prescriptive and goes beyond the associated FERC directive regarding a requirement addressing "capabilities." In particular, these standards were developed to address operator awareness of tool or other outages that could impact real-time monitoring. Further, several of the requirements involve many more entities than the Reliability Coordinators and, absent a requirement for coordination, participation, and action in response to the Reliability Coordinator when an issue is identified, the proposed standard will not achieve its intended objective as written. This is extremely challenging (R1.2) because the majority of issues related to poor data quality or invalid analysis tool solutions can only be resolved by parties outside of the Reliability Coordinator (e.g facility owners, telecom companies, etc.) Additionally, real-time data and monitoring capabilities are critical to the certification of a Reliability Coordinator and are not "dynamic." Because such "capabilities" are complex, require coordination and inputs from other entities, and are key to the continued performance of a Reliability Coordinator's duties, they are not subject to change or revision often and, therefore, likely do not need continued monitoring and assessment. Finally, several other reliability standards and associated requirements are contingent upon the availability of real-time tools and data, which standards and requirements are subject to the compliance monitoring and enforcement program. Thus, ERCOT would recommend that requirements addressing capabilities be utilized during certification and not as a reliability standard subject to the compliance monitoring and enforcement program. Should NERC continue this project, however, ERCOT recommends that they are narrowly focused on alerting and alarming operators when their tools and/or displays are no longer working or otherwise compromised during real-time operations. Accordingly, ERCOT provides the following comments by requirement: **Requirements R1 and R2**

ERCOT respectfully recommends that requirements R1 and R2 be combined. Because the need to address data issues generally arises as a result of a data indicator or the need for manual data intervention by system operators, the value of a process to address such issues without the context of time or need is significantly diminished. Hence, ERCOT proposes the following:

R1. Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R1.1 The Reliability Coordinator shall initiate actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data when failure or degradation is indicated.

Although this change does not accomplish the intended objective since the parties required to respond to the RC's actions initiated to coordinate resolution do not have any requirements to respond or correct the issue, it does however limit the requirements to what the RC as an entity has control over.

Requirements R3 and R4

ERCOT respectfully recommends that requirements R3 and R4 be combined. Because the need to address issues with real-time analyses generally arises as a result of an indicator that a particular analysis did not complete, is offline, or there is a need for manual intervention by system operators, the value of a process to address such issues without the context of time or need is significantly diminished. Additionally, the availability of back up or offline processes for real-time analyses mitigates the risks associated with an issue or outage of analysis capabilities. For R4, specifically "quality" is more ambiguous when considering analysis tools vs data quality. Data quality is more discrete defined by predetermined limits for analog values and logic behind discrete/binary values. Analysis "quality" is not an appropriate term as it infers a range rather than a discrete nature (valid/invalid).Hence, ERCOT proposes the following:

R3. Each Reliability Coordinator shall provide its System Operators with indication(s) of the tool(s) used in its Real-time monitoring and Real-time Assessments are functioning as intended. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R3.1 The Reliability Coordinator shall initiate actions to resolve any issues internally and to coordinate resolution of any data issues that are impacting such tool(s) with entity(ies) responsible for providing data inputs to such tool(s) when failure or degradation is indicated.

ERCOT recommends that necessary revisions be made to the Violation Severity Levels to ensure consistency with the proposed revisions.

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Answer Comment: Neutral position as it does not applies to ITC

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:	No
Answer Comment:	Texas RE recommends making the retention period for R3 longer than 30 days. This requirement consists of a procedure and the implementation of a procedure. A 30 day retention policy will make it very difficult for a registered entity to demonstrate compliance. The policy implies that there is not a reliability issue if compliance monitoring is not performed within 30 days (or every 30 days). Is there an event analysis category that captures quality of data and assessments where the CEA may call for longer retention? Effectively this retention policy is indicative of masking a reliability issue where the quality of the data used in assessments and the quality indication to the System Operators may be inadequate to perform the reliability functions and the only indication of a failure will occur during an event (or the preceding 30 days of a monitoring activity). Texas RE suggests making IRO-018-1 R3, R4 clearer by using some of the language from the rationale. The requirements address “quality of analysis”, which could depend on many factors, while the rationale uses the language “to address issues related to the quality of the analysis inputs used for Real-time Assessments”. Texas RE recommends revising the phrase “with indication(s) of” used in proposed IRO-18-001, R2 and R4 as it is vague. Presumably, the purpose of IRO-18-001, R2 and R4 appears to be to ensure that the results of the required evaluations of potential Real-time data quality discrepancies are communicated to System Operators so they can be incorporated into Real-time monitoring and Real-time assessments. Accordingly, Registered Entities should be required to provide appropriate information from their data quality assessments to their System Operators. Texas RE suggests substituting “relevant information and/or analyses concerning” for “with indication(s) of”

to require appropriate, relevant information and/or any analyses of the quality of Real-time data be communicated to System Operators, not merely indications of data quality.

The reference to “with indications of” in the corresponding measures should also be revised along these lines. However, the types of evidence identified in the measures satisfy the proposed “relevant information and/or analyses concerning” standard.

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: No

Answer Comment:	Southern believes that the criteria in R1.1 should be limited to the RC's ability to monitor and assess the current/expected condition of its RC area within the capabilities of its monitoring tools not including the criteria listed in R1.1.1-R1.1.4. Each RC has the inherent responsibility to protect the integrity of the system in its RC area and contribute to the overall integrity of Interconnection as required by other approved reliability standards. Other approved standards require the RC to have monitoring tools and capabilities to assess system conditions in its area and to perform next day and real time reliability assessments to identify/mitigate potential issues that could have an adverse impact on reliability. In order to fulfill its responsibility, the RC performs monitoring through the information collected from the modeled facilities in its RC area to accurately assess the state of the system and to perform real time assessments. Throughout this process, the RC is constantly evaluating the quality of data received to ensure it has an accurate state of system conditions to perform real time assessments. To impose a new standard focusing on data quality would only serve as administrative in nature and would not provide any substantial increases in reliability.

2. The SDT has proposed a new standard TOP-010-1 to address TOP and BA monitoring and analysis capability issues identified in project SAR. Do you agree with the proposed standard? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

Summary Consideration

TOP Operating Procedures for Real-time data quality. The SDT removed requirement parts that were unnecessarily prescriptive, and clarified the scope of required actions to resolve Real-time data quality issues. In response to issues and concerns from stakeholders explained below, proposed TOP-010-1 Requirement R1 was revised as follows:

R1. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: [Violation Risk Factor: Medium] [Time Horizon: ~~Same Day Operations,~~ Real-time Operations]

1.1. Criteria for evaluating ~~potential~~ the quality of Real-time data; ~~quality discrepancies including, but not limited to:~~

~~1.1.1. Data outside of a prescribed data range;~~

~~1.1.2. Analog data not updated within a predetermined time period;~~

~~1.1.3. Data entered manually to override telemetered information; and~~

~~1.1.4. Data otherwise identified as invalid or suspect.~~

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to ~~coordinate resolution~~ resolve ~~of~~ Real-time data quality issues ~~discrepancies~~ with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

Specific comments and SDT responses are provided below:

- **Some commenters indicated that the proposed Requirement R1 was overly prescriptive or required entities to have criteria for evaluating Real-time data quality that may not apply to all systems used in Real-time monitoring.** The SDT revised this requirement in both of the proposed standards to align with the SDT's intent. The example list of criteria that needs to be addressed in the Operating Procedure or Operating Process has been moved to the guidelines and technical basis section, and the list clearly indicates that only the applicable criteria need to be included.
- **Other commenters suggested including additional details or metrics in the proposed standard to establish criteria for data quality.** The SDT considered alternate requirements/parts to specify data quality within the standard and determined that the best approach for reliability was for applicable entities to determine criteria for evaluating data quality in its Operating Procedures or Operating Processes. This is the approach taken with the proposed standard. The SDT does not believe that there is

a ‘one size fits all’ metric for data quality as part of a continent-wide standard requirement. The SDT believes that the data quality issue is best decided on a case-by-case basis using sound professional judgment and described in the applicable entity’s Operating Procedure or Operating Process.

- **Commenters stated that the some data quality issues were beyond the direct control of the applicable entity. Commenters also proposed adding requirements to compel entities providing bad data to take corrective action.** The proposed standard requires entities to have an Operating Procedure or Operating Process to address the quality of Real-time data necessary to perform Real-time monitoring and Real-time Assessments. Entities have flexibility for determining the appropriate approach for evaluating the quality of their Real-time data, and for determining how to resolve Real-time data quality issues affecting Real-time assessments. The SDT believes an Operating Procedure or Operating Process can be developed to address data quality issues, even if they are beyond the direct control of the applicable entity. To satisfy the intent of the requirement, Part 1.3 requires that actions be taken to resolve data quality issues with the appropriate entities responsible for the data. The SDT does not believe additional requirements in proposed TOP-010-1 are necessary. TOP-003-3 data specification standard establishes obligations for entities to provide data and information to the Transmission Operator.
- **A commenter was concerned that the scope of data to be addressed was too broad.** The SDT modified the requirement (now Part 1.3) and provided a clear description of the SDT's intent in the Guidelines and Technical Basis Section. Requirement R1 Part 1.3 specifies the TOP shall include actions to resolve Real-time data quality issues when its Real-time Assessments are affected. The Operating Procedure or Process should clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to resolve data quality issues in an appropriate timeframe.

BA Operating Procedures for Real-time data quality. The SDT revised proposed Requirement R2 for consistency with proposed Requirement R1.

- **A commenter suggested removal of the reference to the analysis functions performed by the BA.** Proposed TOP-010-1 Requirement R2 addresses the quality of Real-time data required by proposed TOP-003-3 and used in the performance of the BA's Real-time reliability functions. Proposed standard TOP-003-3 Requirement R2 requires the BA to have a data specification for its analysis functions and Real-time monitoring. These analysis functions are described in the NERC Functional Model and other Reliability Standards.
- **A commenter suggested that BA requirements in the proposed standard could create 'double jeopardy' with proposed BAL-005 requirements.** NERC Rules of Procedure Appendix 4B section 2.5 addresses enforcement actions where multiple violations involving more than one Reliability Standard are the result of a single act or common incidence of noncompliance. The requirement in proposed BAL-005-1 is limited to information associated with Reporting ACE, whereas the requirement in proposed TOP-010-1 applies to Real-time data necessary to perform the BA's analysis functions and Real-time monitoring. These functions go beyond BAL-005 as described in the NERC Functional Model and existing and proposed TOP and IRO standards.

Operator awareness of Real-time data and analysis quality. Stand-alone requirements to provide indications of Real-time data quality and analysis quality to System Operators were removed (Requirements R3, R4, and R6 in initial draft standard). The reliability objectives are to be addressed within the applicable entity's Operating Procedures or Operating Processes. Specific comments are below, along with SDT responses:

- **Some commenters suggested combining requirements for Operating Procedures with requirements to provide notifications to operators.** The SDT removed the stand-alone requirement to provide indications of Real-time data and analysis quality and incorporated the objective in requirements for Operating Procedures.
- **Commenters were concerned that the proposed requirement to provide System Operators with indications of data or analysis quality could potentially detract from operator situational awareness, or that evidence of compliance with the proposed requirement for each data point was burdensome.** In the proposed revised standard, entities are required to include provisions for indicating data quality in their Operating Procedures. Provisions could include descriptions of quality indicators that are currently in use, such as display color codes, data quality flags, or other such indicators used by operating personnel as found in Real-time monitoring specifications. This approach provides entities with flexibility to determine how to achieve the reliability objective of providing operators with indications of data quality within the capabilities of existing Real-time monitoring and Real-time Assessment systems. The SDT is not implying that an entity would or should overload the operator with alarm indications of every instance of data quality issues. The SDT believes that the data quality issue is best decided on a case-by-case basis using sound professional judgment and described in the applicable entity's Operating Procedure or Operating Process.

Operating Procedures to address the quality of analysis used in Real-time Assessments. The SDT clarified the scope of actions to resolve analysis quality issues required to be included in an entities Operating Procedure or Operating Process, and added clarifying details to the rationale and Guidelines and Technical Basis section of the proposed standard. Proposed Requirement R3 is revised as follows:

~~R5.~~R3. Each Transmission Operator shall implement an Operating Process or Operating Procedure to ~~maintain~~ address the quality of ~~any~~ analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: [Violation Risk Factor: Medium] [Time Horizon: ~~Same Day Operations,~~ Real-time Operations]

3.1. Criteria for evaluating the quality of ~~any~~ analysis used in its Real-time Assessments; and

~~3.1.~~3.2. Provisions to indicate the quality of ~~any~~ analysis used in its Real-time Assessments; and

~~3.2.~~3.3. Actions to resolve analysis quality issues affecting its Real-time Assessments ~~deficiencies in any analysis used in its Real-time Assessments~~.

Specific comments and SDT responses are provided below:

- **Commenters asked for clarification on what the SDT meant by *any analysis used in Real-time Assessments.*** Analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis, or other studies used for Real-time Assessments. Some entities may use several types of analysis in performing a Real-time Assessment. The Operating Procedure must address the quality of these analysis inputs to Real-time Assessments.
- **Commenters indicated the wording of the proposed requirement was unclear or overly broad.** The SDT revised the requirement by replacing *maintain* with *address*. An Operating Procedure addresses the quality of analysis used in Real-time Assessments by containing: 1) criteria for evaluating quality; 2) provisions to indicate quality to operating personnel; and 3) actions to resolve analysis quality issues affecting Real-time Assessment. The proposed requirement provides entities with flexibility to establish criteria for evaluating quality, accounting for system characteristics, Real-time Assessment approach, and the capabilities of their Real-time tools. The SDT added a non-exclusive list of sources of quality criteria in the guidelines and technical basis section of the standard: "*The entity must use appropriate quality criteria based on the analysis capabilities used to perform Real-Time Assessments, such as solution tolerances, mismatches with Real-time data, convergences, etc.*"
- **A commenter was concerned that requirement part (3.3) wording was overly broad and implied that action was required to resolve every analysis quality deficiency.** The SDT modified the requirement (now Part 3.3) to clarify that the Operating Procedure must include actions to resolve analysis quality issues that affect its Real-time Assessments.
- **A commenter recommended increasing the evidence retention period for this requirement from 30-days.** The evidence retention period is aligned with the evidence retention period for performing Real-time Assessments contained in TOP-001-3 Requirement R13, which is a rolling 30-day window.

Independent Alarm Process Monitoring. Several commenters sought clarification regarding what is meant by an independent alarm process monitor. The SDT The SDT revised the requirement and rationale box to clarify the intent as shown below. " *An ~~independent~~ alarm process monitor is independent if it ~~one that~~ will ~~would~~ not fail with a simultaneous failure of the Real-time monitoring alarm processor. ~~A 'heartbeat' or 'watchdog' monitoring system may accomplish this objective.~~*" The SDT believes the intended capability is appropriately identified by the proposed requirement and the revised rationale box.

- **Some commenters asked if the independent alarm processor needed to be separate from the EMS system.** The proposed requirement does not preclude use of the EMS system as an independent alarm process monitor.

Use of third-party services to perform Real-time Assessments. A commenter recommended the SDT address the possibility that some TOPs use a third-party to perform Real-time Assessments. The proposed definition of Real-time Assessment provides for the use of third-party services. The SDT believes the requirements in proposed TOP-010-1 must be satisfied by the applicable entity, regardless of whether that entity is performing its own Real-time Assessment or it has contracted with a third-party provider.

Time Horizons. A commenter questioned the *same-day operations* time horizon. The SDT agrees that all requirements should be satisfied in Real-time and has removed same-day operations.

Commenters questioned the need for reliability standards to address these issues and suggested that the reliability objectives would be better achieved through Organization Certification program. The proposed requirements in IRO-018-1 and TOP-010-1 address outstanding regulatory directives from Order No. 693 and various industry recommendations as described in the SAR. Although this project was paused in 2011, it received renewed focus in 2012 when FERC identified shortcomings in previously proposed TOP and IRO standards (See FERC Notice of Proposed Remand issued Nov 21, 2013). Project 2014-03 - Revisions to TOP and IRO Standards was initiated to address issues identified in FERC's November 2013 NOPR, however the Project 2014-03 SDT, NERC Staff, and FERC Staff agreed that Real-time Monitoring and Analysis capabilities would not be completely addressed within the project. Accordingly, the Standards Committee authorized resumption of Project 2009-02 in 2015 following NERC's filing of TOP and IRO standards from Project 2014-03. The SDT's experience and the ongoing efforts to improve Real-time situational awareness within the industry indicate that issues of data quality and Real-time analysis quality remain relevant reliability objectives. The proposed standards address these in a manner that provides flexibility for applicable entities to account for system needs and Real-time monitoring and analysis capabilities. Furthermore, addressing these reliability issues through standards ensures ongoing accountability that begins with organization certification and is maintained through day-to-day operations.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:	Clarity is needed regarding how granular the Requirements are to the data points themselves. For example, is the Transmission Operator obligated in R3 to provide indication(s) of quality on a data point basis, or rather, may it be done as a collection of data points, grouping them as needed? Of even greater concern, would the “actions to coordinate resolution” in R1 need to be performed on a per-data point basis as well? Hundreds of thousands of data points are involved in Real-time monitoring and Real-time Assessments, and the requirements in this standard must be written realistically to accommodate a high volume of data points which continue to increase. In addition, AEP has a large volume of data provided by external entities. AEP would have little to no ability to “coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data” as specified in R1.2, for this externally provided data. Perhaps a re-ordering of the TOP-10-1 requirements could help the overall flow of the standard. For example, it may be preferable to have a Requirement for indications of quality (R3 for example) to precede a Requirement to have an Operating Process or Operating Procedure to address the quality of that data (R1 for example).

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:	No
Answer Comment:	**We do not agree with the need to create this standard, and the way the proposed standard is drafted (overly prescriptive and micro-managing). Please see our comments under Q1**.

Tyson Archie - Platte River Power Authority - 5 -

Selected Answer: No

Answer Comment:

Platte River (PRPA) like many smaller TOP's does not have an EMS system capable of performing Real-Time Assessments. To accomplish this task, we contract our Reliability Coordinator to run our Real-Time Assessments. Platte River provides data points to the RC, who runs the Real-Time Analyses and then provides PRPA with the advanced applications.

PRPA does not have a concern with the intent of the standard, but requests that the drafting team address the possibility of relying on 3rd party contracts to perform Real-Time Assessments for entities that do not possess the ability to perform each of the requirements in this standard.

Without the ability to contract a 3rd party for these services, the financial burden of purchasing and installing a new EMS system capable of performing these tasks would easily reach into the millions of dollars.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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

Answer Comment:	R1 and R2: It can be very difficult to identify some of the real-time data quality problems listed in this Standard, particularly analog data that is not updating. Many current systems do not have the capability to easily detect this for all analogs, and adding this capability for all data points could require extensive Software, database, and/or Hardware (for performance reasons) changes that cannot be easily or quickly implemented. As real-time telemetry becomes more de-centralized in the field and as we are required to rely more and more on data from other entities (via ICCP), it becomes more and more difficult to detect data that is out of range. Putting this requirement on an entity that has no control over the source of the data or how it is provided seems to put an unfair regulatory burden on that entity. Most of the real-time data quality criteria seem focused on analog data, but incorrect digital data can have a greater impact on analysis results than incorrect/stale analog data. However, identifying non-updating digital data can be even more difficult than identifying non-updating analog data. How do we prove to an auditor that we identified all instances of data with poor quality? These requirements seemed focused on evaluating the quality of incoming real-time data. Are there any requirements for providing accurate quality codes with data? For example: Both ICCP and some RTU protocols support including quality codes with data values. For example, if an entity receiving ICCP data relies on these quality codes to at least partially determine the quality of a data point, then the received quality codes need to be accurate.

	Both ICCP and some RTU protocols support including time-stamps of the most recent change of a data point value. Some systems use this received time-stamp when processing the data, and it can impact applications used by operators, including where a new alarm for that point appears in an EMS/SCADA alarm list. Receiving an incorrect time-stamp can negatively impact the information and results provided to an operator. R3 and R4: What is considered sufficient notification to an operator of real-time data quality problems? If quality codes are shown on EMS/SCADA displays, an operator may not look at the displays with data quality issues. But if alarms are generated to notify the operator, the increase in alarm volume may detract the operator's attention from more important alarms. Summarizing the quality of thousands of real-time measurements for an operator may not be something existing systems can easily do. This may require software and possibly hardware additions to an EMS/SCADA. R5: There is no guidance provided for a Transmission Operator to create criteria to evaluate the quality of analysis used in its Real-time Assessments. If an auditor will be expected to review the criteria used by a Transmission Operator, the guidelines that will be provided to auditors for this purpose should be listed here. R7: With current EMS/SCADA architectures, it can be difficult to define what comprises the "alarm processor". While requirements R1-R4 of this Standard may cover the quality of the telemetered inputs to the EMS/SCADA, there are many EMS/SCADA components used after that to make operators aware of alarms. It is not just a specific alarm processing program, but also includes things such as the EMS/SCADA data dissemination programs, the EMS/SCADA User Interface application, audible alarming capabilities, even the operator

	console hardware itself. Should this requirement be re-worded to make it clearly cover the ability of the system to make alarms available to operators and not imply it is limited it to a specific “program”? VSLs: R3 & R4: It is not clear from the wording of the single VSL level (which is Severe) if a violation of this Standard is incurred only if there are NO indications of quality of real-time data. If the meaning is to include situations where one or a few points with bad quality are missed (i.e., not notified to an operator) than assigning a Severe VSL seems inappropriate, and several levels of violations should be implemented. R6: Is it correct that a violation of this Standard is incurred only if there are NO indications provided to operators of poor quality of analysis results, and that missing some number of these instances is not a violation of this Standard? If the intent is to consider even a single miss a violation then assigning it a Severe VSL seems inappropriate, and several levels of violations should be implemented. R7: Is it correct that occasional failures of the independent alarm process monitor are not violations of this Standard?
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 - Selected Answer:	 No

Answer Comment:	We would like to see "quality" defined or clarrified. Also, we are not sure who is responsible for the quality of the data received from the interconnections. We also support some of the comments coming out of the MRO standards group.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:	Yes
Answer Comment:	***ATC supports the comments submitted by the MRO NSRF.*** However, raise the following question: Does having a process or procedure support your quality of Real-time data? It's not the process or procedure but rather what systems do you have in place to alert the TOP/BA that there is an issue with your data (R1.1 – R1.2). **R1 and R2:** o It can be very difficult to identify some of the real-time data quality problems listed in this Standard, particularly analog data that is not updating. Many current systems do not have the capability to easily detect this for all analogs, and adding this capability for all data points could require extensive Software, database, and/or Hardware (for performance reasons) changes that cannot be easily or quickly implemented. As real-time telemetry becomes more de-centralized in the field and as we are required to rely more and more on data from other entities (via ICCP), it becomes more and more difficult to detect data that is out of range. Putting this requirement on an entity that has

o no control over the source of the data or how it is provided seems to put an unfair regulatory burden on that entity.

o Most of the real-time data quality criteria seem focused on analog data, but incorrect digital data can have a greater impact on analysis results than incorrect/stale analog data. However, identifying non-updating digital data can be even more difficult than identifying non-updating analog data.

o How do we prove to an auditor that we identified all instances of data with poor quality?

o These requirements seemed focused on evaluating the quality of incoming real-time data. Are there any requirements for providing accurate quality codes with data? For example:

§ Both ICCP and some RTU protocols support including quality codes with data values. For example, if an entity receiving ICCP data relies on these quality codes to at least partially determine the quality of a data point, then the received quality codes need to be accurate.

§ Both ICCP and some RTU protocols support including time-stamps of the most recent change of a data point value. Some systems use this received time-stamp when processing the data, and it can impact applications used by operators, including where a new alarm for that point appears in an EMS/SCADA alarm list. Receiving an incorrect time-stamp can negatively impact the information and results provided to an operator.

R3 and R4:

o What is considered sufficient notification to an operator of real-time data quality problems? If quality codes are shown on EMS/SCADA displays, an operator may not look at the displays with data quality issues. But if alarms are generated to notify the operator, the increase in alarm volume may detract the operator's attention from more important alarms.

o Summarizing the quality of thousands of real-time measurements for an operator may not be something existing systems can easily do. This may require software and possibly hardware additions to an EMS/SCADA.

R5: There is no guidance provided for a Transmission Operator to create criteria to evaluate the quality of analysis used in its Real-time Assessments. If an auditor will be expected to review the criteria used by a Transmission Operator, the guidelines that will be provided to auditors for this purpose should be listed here.

R7: With current EMS/SCADA architectures, it can be difficult to define what comprises the "alarm processor". While requirements R1-R4 of this Standard may cover the quality of the telemetered inputs to the EMS/SCADA, there are many EMS/SCADA components used after that to make operators aware of alarms. It is not just a specific alarm processing program, but also includes

· things such as the EMS/SCADA data dissemination programs, the EMS/SCADA User Interface application, audible alarming capabilities, even the operator console hardware itself. Should this requirement be re-worded to make it clearly cover the ability of the system to make alarms available to operators and not imply it is limited it to a specific "program"?

VSLs:

o R3 & R4: It is not clear from the wording of the single VSL level (which is Severe) if a violation of this Standard is incurred only if there are NO indications of quality of real-time data. If the meaning is to include situations where one or a few points with bad quality are missed (i.e., not notified to an operator) than assigning a Severe VSL seems inappropriate, and several levels of violations should be implemented.

o R6: Is it correct that a violation of this Standard is incurred only if there are NO indications provided to operators of poor quality of analysis results, and that missing some number of these instances is not a violation of this Standard? If the intent is to consider even a single miss a violation then assigning it a Severe VSL seems inappropriate, and several levels of violations should be implemented.

R7: Is it correct that occasional failures of the independent alarm process monitor are not violations of this Standard?

Likes:	1	Grand River Dam Authority, 3, Wells Jeff

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment:	The SRC fails to see the reliability risk that this project is intending to address. The August 14 Blackout as well as the 2011 Southwest Outage have thoroughly and exhaustively investigated, reported upon, and the root causes mitigated appropriately. Therefore, pointing to the need for this project based on mitigated, historical events falls short of identifying the reliability risk that this is intended to "fix." If, for example, WECC continues to have a vested interest in further mitigating the 2011 Southwest Outage though standard development, we suggest this project be migrated into a regional standard for WECC. Lastly, the SRC believes that, absent a Standard specific for tools, a RC, TOP, or BA would, in fact, have violations of existing operational Requirements if they do not provide adequate monitoring and tools to their operators (i.e. other "things" would happen). Further, the Requirements as written, "…to address the quality of the Real-time data necessary…" are ambiguous, lack consensus about how to measure, and do not rise to the level of a NERC Standard. This proposed project appears to be well-suited for a guideline document as opposed to a Standard. As written, the SAR appears to intend to write a "how" not "what" Standard (*i.e.*, it does not appear to be a results-based standard). The SRC believes that the existing Standards (*i.e.*, IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (*i.e.*, without defining the "how"), which is appropriate. In the alternative, this could be considered a process to be used for Certifying new entities, in line with a methodology developed by the ERO and registered entities for assessing adequacy of tools for addressing the "quality" of real-time data, for assurance that RC, BA and TOPs have the ability to monitor appropriately in accordance with existing, performance-based Standards Requirements. The SRC notes that the tools available to operators have progressed well beyond those available in 2003. If defined tools would have been hardcoded

	in a standard at that time, it would have limited focus and investment to those things that were in the standard. Further, expanding on our point above, the SRC believes that the "what" regarding tools is more appropriately captured in the certification expectations for BAs, RCs, and TOPs. Additionally, it would be appropriate for Regions to evaluate tools as part of the Registered Entity's Inherent Risk Assessment (IRA). This would include the scope of tools, backups, etc. and would provide an adaptable approach that would encourage continuous improvement. Additionally, the SRC recommends that NERC coordinate with the NATF to encourage inclusion of an ongoing "care and feeding" of tools evaluation and information sharing in their efforts with the provision that they make information on good practices available to the wider NERC community so that non-members can learn from the innovation of others. Finally, to avoid these issues in the future and to support communicating to FERC when a Standard is not needed and another tool is more suitable, the SRC suggests that future SARs be voted on by industry to determine whether they should proceed as a Standards project or another means is a more appropriate method through which to achieve the SAR's objective.

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer:	No
Answer Comment:	RC, BA & TOP entities currently have adequate tools for real-time monitoring and analysis. The existing Standards adequately define what needs to be monitored by each entity without defining the tools. Creating new requirements will not increase the reliability of the BES.

	Additionally, some of the new proposed requirements (IRO-018-1 Req. 1, TOP-010-1 Req. 1) state: Each RC/TOP/BA shall implement and Operating Process to address the *quality* of the Real-time data… the term *quality* is ambiguous and subjective. This term needs to be defined. Similar to Requirement 2, the terms *indications of quality* needs to be defined. If not defined, it could result in varying interpretations throughout the industry. Lastly, the NERC Operating Reliability Subcommittee (ORS) has drafted a Reliability Guideline, "Loss of Real-Time Reliability Tools Capability / Loss of Equipment Significantly Affecting ICCP Data." This guideline will help ensure that tools are adequate and if they are degraded for any reason, the potentially impacted entities are aware and can take action if needed. PJM supports the comments submitted by the ISO/RTO Council Standards Review Committee.	
Likes:	5	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph Long Island Power Authority, 1, Ganley Robert PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer:	No

Answer Comment:	R1.1 uses “but not limited to”. That language is too open ended and cannot be audited or compliance limited. Compare it to R3. ‘ But not Limited to” only belongs in a Measurement. R2 is ambiguous in whether a single data point of bad quality needs to be flagged or if the aggregate data is so bad that state estimator can’t solve. Modern EMS systems incorporate data quality checks within their algorithms. However, how this requirement is phrased will dramatically impact the compliance risk an organization faces.

Darnez Gresham - Darnez Gresham On Behalf of: Thomas Mielnik, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3

Selected Answer:	No

Answer Comment:	The MidAmerican Energy Company (MEC) has concerns with redundancy and technical complications with the TOP-010 standard as proposed. The data quality objective can be simplified into a single requirement in either TOP-010-1 or TOP-001-3 which is for entities to have tools or processes that consider data quality to reasonably assure a reasonably high confidence that the system is in a reliable state. Existing Energy Management Systems (EMS) and Real-Time Contingency Analysis (RTCA) tools already have this capability. **Redundancy:** The MEC recognizes that FERC directed the drafting team to address missing data quality issues based on the 2003 blackout report. However, existing standards TOP-001-3 and TOP-003-3 already require effective monitoring and control which includes proper data quality. As an example, R13 of TOP-001-3 sets clear requirements that a real-time assessment must be performed at least once every 30 minutes. That requirement includes the identification and consideration of data quality to provide successful assessment solutions at least once every 30 minutes. TOP-001-3 R13 requires TOPs to have operating processes or procedures that address issues bad data detection and identifications that are likely to cause assessment failures such as non-convergence or invalid solutions. All TOPs assessment tools already consider bad data detection and identification from embedded software algorithms which are pre-requisites for successful execution of SE/RTCA. TOP's engaged in monitoring the execution of their assessment tool(s) already address problems with data input quality and assessment quality. Assessment tools must have robust data quality input and assessment capabilities to detect and identify problem(s) with any single piece of data

(out of thousands of inputs) especially if that particular bad input (or limited set of bad input data) did NOT affect overall successful performance of the tool.

Technical Compliance Complications that Distort the Reliability Goal:

The zero defect nature of compliance, until fixed, drives unnecessary costly EMS / RTCA system upgrades without measureable system reliability improvements. The proposed TOP-010 standards introduce vague and unclear formulations that will cause misunderstandings during compliance audits. Therefore, it is better to revise TOP-010 to a single requirement or revise TOP-001-3 or TOP-003-3 with an additional simple requirement for entities to have tools or processes that considers data quality to reasonably assure a high confidence that the system is in a reliable state.

Assessment tools use thousands of input data points including analog measurements and switching device statuses. Therefore, the reliability goal(s) are that the assessment tool has bad data detection and identification algorithms that allow the assessment tool to solve, and notify / log the system operator of bad data, and alarm if the bad data may compromise the assessment or solution.

Identifying vague input data issues such as “analog data not updated” or “data identified as suspect” is problematic from a compliance standpoint. Some Energy management Systems (EMS) simply do cannot identify all suspect data and therefore the zero defect compliance expectation to identify all suspect data or all bad analog data is technically infeasible. The reliability goal is a high confidence assessment that the system is in a reliable state. That is very different from the stated compliance zero defect standard as written to identify all “analog data not updated” or identify “all suspect data”.

	Significant technical problems exist with the TOP-010 requirements when applied to input data received from other TOPs or RC's (either directly or via ICCP). There are no technically feasible mechanism to detect for "manually entered statuses. An example is detecting a manually entered "CLOSED" circuit breaker status whose actual status is "OPEN", if such data was received via ICCP. TOP-010 R3 is unclearly defined as Transmission Operators would have major difficulty in coming up with a conclusion as to what is "the quality of data necessary to perform real-time assessment". At any moment in time, any specific measurement (or subset of measurements) might either be lost or be detected as "bad". That does not necessarily mean that the real-time assessment would be inaccurate or invalid. The tool's accuracy can be measured by other inherent quantitative indicators such as algebraic sum of allocation errors" or "confidence percentile". An aggregate reasonable confidence percentile measurement would be a sufficient system reliability objective reasonably proving the system was in a reliable state. TOP-010 R5 introduces unclear terminology of "maintaining the quality of any analysis used in real-time assessment".

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer:	No

Answer Comment:

PGE thanks the drafting team for their efforts regarding the development of this proposed standard. After meeting with the SMEs involved with the proposed standard, they've provided the following:

SUMMARY

• We recommend a “No” vote on TOP-010-1 at this time because we feel additional clarity is needed.

• Submit comments on the following:

◦ Requesting clarification on the meaning of *analysis* and *Real-time Assessments*. (Human or machine.)

◦ If R5 is addressing the knowledge or ability of operators, it belongs in PER-005, not here.

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: No

Answer Comment:

R1, R2, R3, & R4: Duke Energy questions the use of the term “analysis” in R2 and R4, attributable to the BA, but is not present in R1 and R3 that is attributable to the TOP. The use of the term analysis in this context suggests that the BA has some sort of responsibility to carry out analyses similar to that of the RC or TOP. We disagree with this premise. Also, we question why the term “analysis” is not present in R1 or R3. The TOP does in fact have responsibilities to carry out analyses, and this should be acknowledged in R1 and R3. Duke Energy suggests that all references to the BA performing an analysis be removed in all attributable requirements, and that analysis that are expected to be performed by the TOP be referenced in requirements attributable to it.

R5: We request further clarification on the use of the phrase “analysis inputs” in the Rationale of R5, as opposed to the use of the term “analysis” in the wording of R5. Is the use of “inputs” meaning other types of data or operational conditions that aren’t described in R1-R4? More clarification regarding what is meant by the phrase “analysis inputs” would be helpful.

R7: Duke Energy requests further explanation on what it meant by the use of the term “processor” in regards to the failure of a Real-time monitoring of an alarm processor. Is this referring to independent hardware that monitors EMS/SCADA or independent processes within the EMS system? Is separate hardware necessary, or will separate processes be sufficient? Should this be something that is housed outside of the EMS? We feel that an example of what is meant by independent (does this mean external?), as well as “processor” would enhance clarity in this requirement.

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
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
Mark Schultz	City of Green Cove Springs	FRCC	3
Chris Adkins	City of Leesburg	FRCC	3
Ginny Beigel	City of Vero Beach	FRCC	9

Selected Answer: No

Answer Comment:

In part 1.1 of R1, if the bulleted list is intended to be an example list, then the examples should not be given part numbers but should be rolled up into the main sentence. If it is intended to be a minimum set of criteria, then “but not limited to” should be replaced with “at a minimum”.

In part 2.1 of R2, if the bulleted list is intended to be an example list, then the examples should not be given part numbers but should be rolled up into the main sentence. If it is intended to be a minimum set of criteria, then “but not limited to” should be replaced with “at a minimum”.

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer:	No
Answer Comment:	This standard creates a double jeopardy situation. Requirement R1 Part 1.2 of this standard specifies the TOP shall include actions to coordinate resolution of Real-time data quality discrepancies in its Operating Process or Operating Procedure. These actions are also required by proposed TOP-003-3 Requirement R5 Part 5.2 which requires a process to resolve data conflicts for the data required by the data specification in Requirement TOP-003-3 R3. If that data specification requires the provision of Real-time data, then TOP-003-3 Part 5.2 requires a process to resolve data conflicts and quality discrepancies with that Real-time data. Suggested wording: **R1.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data**, excluding Real-time data already addressed by TOP-003-3 R5 Part 5.2,** necessary to perform its Real-time monitoring and Real-time Assessments.

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1 -

Selected Answer:	No

Answer Comment:	CenterPoint Energy feels R1.1.2 (Analog data not updated within a predetermined time period) brings more of a compliance burden than a reliability benefit. CenterPoint Energy has confidence System Operators investigate and communicate these issues upon suspicion; however, defining a predetermined time period for a data quality code check including each individual piece of data poses a threat to the System Operator's focus monitoring important issues on the grid. CenterPoint Energy also realizes there is a challenge in deciphering whether or not a value has simply not changed in a predetermined time period or if that value hasn't updated. CenterPoint Energy recommends the SDT clarify that 1.1.2 refers to the universe or a pre-defined subset of data and not specific to any one, individual piece of data.

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 does not support the proposed Reliability Standard TOP-010-1. We also believe that these requirements are too prescriptive (the "how") and is moving away from the result-based approach (the "what").

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:	Yes

Brent Ingebrigtson - PPL NERC Registered Affiliates - 1,3,5,6 - SERC,RFC

Group Name: PPL NERC Registered Affiliates

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E and KU Energy, LLC	SERC	1,3,5,6
Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
Dan Wilson	LG&E and KU Energy, LLC	SERC	5
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6

Selected Answer: No

Answer Comment:

Comments: These comments are submitted on behalf of the following PPL NERC Registered Affiliates ("PPL"): Louisville Gas and Electric Company, Kentucky Utilities Company and PPL Electric Utilities Corporation. The PPL NERC Registered Affiliates are registered in two regions (RFC and SERC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

The PPL NERC Registered Affiliates believe if additional requirements are necessary for TOP's and BA's to address the quality of their Real-time data, then these requirements should be included in the proposed Reliability Standard TOP-003-3. Per TOP-003-3 (pending regulatory approval) , TOP's and BA's are required to maintain a documented specification for the data necessary to perform its Real-time monitoring and Real-time assessments including periodicity for providing data and a mutually agreeable process for resolving data conflicts. Therefore, adding additional requirements to TOP-003-3 to address the quality of the TOP and BA specified data is less of a compliance burden to stakeholders than creating a new standard.

If the SDT chooses to continue with the proposed TOP-010 standard, we request the sub-requirements R1.1.1 thru 1.1.4 and R2.1.1 thru 2.1.4 be removed from the proposed TOP-010 to allow entities the flexibility to write an Operating Process or Operating Procedure tailored to their system and their Reliability Coordinators specifications where applicable.

Thomas McElhinney - JEA - 1,3,5 - FRCC

Group Name: JEA

Group Member Name	Entity	Region	Segments

Ted Hobson	JEA	FRCC	1
Garry Baker	JEA	FRCC	3
John Babik	JEA	FRCC	5

Selected Answer: No

Answer Comment: The independent monitoring needs to be better clarified. Does independent mean another system besides EMS? We also believe that the terms quality and indicators are vague.

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SERC,SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
John Allen	City Utilities Springfield Missouri	SPP	1,4
Darryl Boggess	Western Farmers Electric Cooperative	SPP	1,5
Donald Hargrove	Oklahoma Gas and Electric	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Robert Hirchak	CLECO	SPP	1,3,5,6
J. Scott Williams	City Utilities of Springfield Missouri	SPP	1,4
Sing Tay	Oklahom Gas and Electric	SPP	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5

Kyle McMenamin	Xcel Energy	SPP	1,3,5,6

Selected Answer: No

Answer Comment:

Following are the same comments we provided on IRO-018-1 draft. They are generally applicable to the proposed TOP-010-1 Standard also.

We do not believe the issues addressed by the FERC directive rise to the level of requiring a reliability standard. The intent of the directive and the resulting actions to be taken by the various entities would be better served by an official Guideline rather than a generic standard. Forcing this into a Standard requires a one-size fits all approach that is leading to varied interpretations on “quality” and “adequacy” and may not enhance reliability of the BES.

We believe the requirements in general could be improved to be more results based. As written, they largely will only result in identifying deficiencies after the fact when doing event analysis. An entity may have a process or procedure as required, but they could miss a piece of data or fail to identify fully the impact a quality issue may have upon their situational awareness. Simply having the process does not result in increased reliability.

Most entities already have a process in place to alarm or indicate data quality as needed to maintain reliability. Entities are already required to operate reliably, within SOLs and IROLs, etc. The creation of this standard as written would serve only to document that process and put it under auditable enforcement – with no discernible impact to maintaining reliability. In order to make this standard truly results based, there needs to be some identification of the quality level, or data quality thresholds that must be maintained in order for reliability to be maintained. Then that level (or quality of the data measurements) must be maintained per the standard.

We suggest that there needs to be more direction given by the Standard in a few areas. One is that the applicable entity should be determining a data range, time periods, number of manually entered values, etc. that can degrade analysis to the point reliability is threatened (R1.1.1-R1.1.4).

We also find it problematic when an entity may not “own” the data and is simply receiving a quality flag from a sender. The RC for example may not receive an accurate quality flag or the quality flag is corrupted in translation over ICCP. Also, there is no requirement that the measurement devices even be of a particular accuracy. For example the quality threshold may be more narrow than the accuracy of the device.

The use of the term “suspect” in R2.1.4 in TOP-010-1 could lead to an interpretation that the operator “should have suspected” the data was incorrect. The word “suspect” is used in some EMS packages as an identifier for garbage or data that is suspect. We recommend the word be evaluated and replaced.

R3 is very problematic in that it infers there is a level of in-adequacy that studies must not fall below when requiring a level of “quality” to be maintained. This seems to be an attempt to not use the word “adequate”. Without defining the required level of quality, there is no way an entity can be compliant. Any entity may experience some reduced level of quality, but may still have acceptable performance from their studies without taking action to correct or mitigate the data. As written, the entity would be in violation for simply failing to “maintain” the level of quality. Perhaps R3 could be written this way:

R3. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to maintain an acceptable level of quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

3.1. Criteria for determining the minimum quality of any analysis used in its Real-time Assessments; and

3.2. Actions to resolve unacceptable quality deficiencies in any analysis used in its Real-time Assessments.

R4 seems to be applicable to situations where a tool is used to perform the RTA. This can become problematic when the assessment is simply an evaluation done by reviewing data and determining that no changes on the system have occurred such as could occur with a TOP who has only a few BES elements and does not possess an EMS or RTCA style "tool".

We suggest that altering the phrase “independent alarm process monitor” could be beneficial. As stated, the phrasing seems to suggest particular processes or tools rather than the intent to just have an “independent process” to monitor the alarming system. We suggest the change as:

R5. Each Reliability Coordinator shall utilize a process to independently monitor its Real-time monitoring alarm process monitor in order to provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Jack Stamper - Clark Public Utilities - 3 -

Selected Answer: No

Answer Comment: Some of the criteria listed in R1.1 is confusing. Data outside of prescribed data range would more likely indicate unusual system conditions rather that a data quality issue. We are currently unsure how the monitoring of these criteria could be implemented without additional software. Also, since implementation is part of the Measurement we would assume some logging of this implementation would be necessary to prove compliance which is also a process without and obvious means of accomplishment. There needs to be some substantial guidance or technical discussion providing information on what would be the expectations for utilities to be in compliance with this standard.

Megan Wagner - Westar Energy - 6 -

Selected Answer: No

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: Project 2009-02

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Michael Forte	Con Edison	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1

Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
Kelly Dash	Con Edison	NPCC	3
Michael Jones	National Grid	NPCC	3
David Burke	Orange and Rockland Utilities	NPCC	3
Peter Yost	Con Edison	NPCC	4
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7

Selected Answer: No

Answer Comment:	Each requirement is unique to a particular functional entity. Requirements can be eliminated by having each requirement refer to Transmission Operator and Balancing Authority. Similarly to IRO-018-1, language in R1.1 uses “but not limited to”. That language is too open ended and cannot be audited. Compare it to R3 use of “shall include”. “But not limited to” only belongs in a Measurement. R2 is a bit ambiguous in whether a single data point of bad quality needs to be flagged or if the aggregate data is so bad that the state estimator can’t solve. Suggest replacing the word “any” from R5 and R6 (relative to “any analysis”) and replacing with “reliability related” as “any” could be too broadly applied or interpreted. Additionally, the term analysis is broad. Standards related to Project 2014-03, approved through NERC as of this time, define such things as Real Time Assessments and Operational Planning Analysis. It’s not exactly clear what analysis would be referring to.

Glenn Pressler - CPS Energy - 1 -

Selected Answer:	No
Answer Comment:	R5: Need to clarify. What is “quality of any analysis used”? Need to clarify & better define. How is SO notified & Will SO need evidence? R7: Regarding “independent alarm process monitor (IAPM)”: Need more clarity; is this separate from the SCADA data /SCADA system? Is an IAPM separate from SCADA system? Need more clarity.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5

Selected Answer: No

Answer Comment: (1) The standard has significant burdens on System Operators to demonstrate compliance. Requirements R2, R3, and R5.2 expect solution frequencies every 5 minutes, 12 times an hour, 288 times a day. Does each quality deficiency occurring during this period need to be resolved? A RTU communication issue lasting only 10 minutes would impact a minority number of these instances and generate unnecessary work for a system operator. We believe the SDT should provide some qualifier for this requirement.

(2) We believe this standard has the potential to add to the System Operator's workload and take their attention away from their duties of monitoring system reliability. NERC has spent significant efforts to educate industry on situational awareness and human performance topics, including cognitive overload where too much stimuli affecting a System Operator will have negative effects on their performance.

(3) The standard also introduces potential double jeopardy concerns between requirements TOP-010 R2 and BAL-005 R5. At the time of the webinar, the SDT did not look into these possibilities. However, NERC did later respond to the potential double jeopardy with the following statement:

"R5 in proposed BAL-005-1 is limited to information associated with Reporting ACE. R2 in proposed TOP-010-1 applies to Real-time data necessary to perform the BA's analysis functions and Real-time monitoring. These functions go beyond BAL-005 as described in the NERC Functional Model and existing and proposed TOP and IRO standards. Double jeopardy is never an issue because NERC Rules of Procedure include provisions for handling incidences of non-compliance with two or more requirements. Specifically, NERC or the regional entity would issue a single penalty or sanction as called for in the Rules of Procedure (Appendix 4B, Section 2.5)."

We disagree with this approach, as the ROP is focused on being in violation of a single requirement or sub-requirement, not to separate requirements. The issue of double jeopardy could occur when there is an event based on poor ACE data quality, which could also implicate TOP-010-1. While TOP-010-1 contains additional data, it is possible to be in violation of two requirements for the same instance, which is the very definition of double jeopardy. The NERC ROP does not provide relief for this situation.

(4) We have concerns with the potential impact to a System Operator's general awareness of the system. The System Operator will now be spending

	more time logging and performing actions strictly for compliance instead of BES Operation activities. While we understand that the proposed standard allows the entity to determine the amount of operator action needed, can this be similarly defined in a Process or Procedure? We have concerns that an auditor may not interpret the standard to allow other employees to mitigate any data or analyze errors, such as an EMS Engineer or other support personnel. We request that the SDT consider revising the standard to clarify that a System Operator does not specifically have to be the one who mitigates such issues. Furthermore, how does the SDT expect entities to show compliance with "implementation" of their Process of Procedure? (5) The proposed standard includes requirements that should enhance, not detract, from the System Operator's situational awareness since it is based on recommendations from the RTBPTF report. The SDT is mindful that System Operators need to remain focused on relevant real-time information while carrying out their duties. The proposed requirements should provide entities the flexibility to determine which operating personnel carry out required actions. Implementation could be demonstrated through evidence that the Operating Process or Procedure is used for its intended purpose. This evidence which might include checklists, operator logs, or operations support logs, for example. (6) Compliance with the proposed requirements is not evaluated by counting quality codes on data points. The measures, VRFs, and VSLs are constructed to evaluate the capability-based performance requirements, as described in section 2.4 of the SPM. This section states that Capability-based Requirements are defined capabilities needed by one or more entities to perform reliability functions which can be measured by demonstrating that the capability exists as required.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:	Yes

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:	No
Answer Comment:	ReliabilityFirst offers the following comments for consideration:

1. **Requirement R3 and R4**

i. It is unclear as to what the phrase “indication(s) of the quality of the Real-time data” is referring to. RF requests clarification on the term “indications” and what this involves.

i. Also, since the System Operators work for the respected TOP or BA, it is unclear whom at the respected TOP or BA will be providing “indications” to the System Operators. As written, the System Operators (working for the TOP or BA) could provide indications to themselves. This does not seem to be the intent of the Requirement.

2. **Requirement R6**

i. It is unclear as to what the phrase “indication(s) of the quality of any analysis…” is referring to. RF requests clarification on the term “indications” and what this involves.

i. Also, since the System Operators work for the TOP, it is unclear whom at the TOP will be providing “indications” to the System Operators. As written,

	the System Operators (working for the TOP) could provide indications to themselves. This does not seem to be the intent of the Requirement.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:	No
Answer Comment:	Comments: ERCOT reiterates its comments above as applicable to TOP-010-1. Should NERC continue this project, however, ERCOT provides the following comments by requirement: Requirements R1 and R3/Requirements R2 and R4 ERCOT respectfully recommends that requirements R1 and R3 and Requirements R2 and R4 be combined. Because the need to address data issues generally arises as a result of a data indicator or the need for manual data intervention by system operators, the value of a process to address such issues without the context of time or need is significantly diminished. Hence, ERCOT proposes the following: R1. Each Transmission Operator shall provide its System Operators with indication(s) of the quality of Real-time data necessary to perform its Real-time monitoring and Realtime Assessments. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R1.1 The Transmission Operator shall initiate actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data when failure or degradation is indicated. R2. Each Balancing Authority shall provide its System Operators with

	indication(s) of the quality of Real-time data necessary to perform its analysis functions and Real-time monitoring. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R2.1 The Balancing Authority shall initiate actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data when failure or degradation is indicated. **Requirements R5 and R6** ERCOT respectfully recommends that requirements R5 and R6 be combined. Because the need to address issues with real-time analyses generally arises as a result of an indicator that a particular analysis did not complete, is offline or there is a need for manual intervention by system operators, the value of a process to address such issues without the context of time or need is significantly diminished. Additionally, the availability of back up or offline processes for real-time analyses mitigates the risks associated with an issue or outage of analysis capabilities. Hence, ERCOT proposes the following: R3. Each Transmission Operator shall provide its System Operators with indication(s) of the tool(s) used in its Real-time monitoring and Real-time Assessments are functioning as intended. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R3.1 The Transmission Operator shall initiate actions to resolve any issues internally and to coordinate resolution of any data issues that are impacting such tool(s) with entity(ies) responsible for providing data inputs to such tool(s) when failure or degradation is indicated.

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer:	No
Answer Comment:	R1 and R2: The requirements are vague as to what constitutes quality. Do we consider out of tolerance? High value? Low value? What is too high? What is too low? R3 and R4: If quality alarms are generated to alert the operator, the increase in alarm volume may distract the operator from more important alarms. If quality codes are shown on the EMS/SCADA displays, an operator may not look at or notice the displays with data quality issues. Summarizing the quality of thousands of real-time measurements for an operator may not be something existing systems can easily do. This may require software and possibly hardware additions to an EMS/SCADA. R5: TOP-001-3 R13 requires that a real-time assessment is performed at least once every 30 minutes. In order to resolve any issues with the quality of analysis for the real-time assessment outside of normal business hours may require staff to come into the office to resolve which may take more than 30 minutes. This would put an entity out of compliance with TOP-001-3, unless staffing is increased which may not be feasible. There is no guidance provided to create criteria to evaluate the quality of analysis used in Real-time Assessments. There could be discrepancies between an auditor and an entity over what is acceptable criteria. Guidelines that will an auditor could be expected to review should be listed.

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:	No
Answer Comment:	The criterion specified in R1.1 and R1.2 is too prescriptive. The requirements as written are requiring System Operators to monitor the quality of all data specified per proposed TOP-003-3 R1. In a Real-time system there are thousands of data points used and having a few of those outside prescribed data range or not updated within a predetermined time period may have no impact on BES reliability. Requiring System Operators to track the quality of all data can be a distraction and an unnecessary burden. ITC believes the intent of the standard is for entities to pay attention to quality of certain pre-identified data used in Real-time monitoring and analysis. However, the future standard TOP-003-3 will result in this requirement being applied to all data used in Real-time monitoring and analysis. Transmission Operators are required to perform a Real-time assessment and these assessments most commonly utilize tools which are designed to reduce dependencies on bad, invalid, or suspect data therefore placing a requirement for evaluating invalid or suspect data in Real-time does not provide any reliability benefit. The proposed TOP-001-3 R1 requires that each Transmission Operator (TOP) shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. Proposed TOP-001-3 R10 requires TOP to determine SOL exceedances and TOP-001-3 R12 requires TOP to not operate outside IROL for more associated IROL Tv. These requirements together inherently imply that the Transmission Operator should ensure quality of data used in Real-time to get the desired outcome from the Real-time Assessment which is to maintain reliability of its area by monitoring SOLs and IROLs and taking appropriate actions. The proposed TOP-010-1 R1 seems to be specifying 'How to' comply with these requirements which does not meet the result base standard practice. In addition, the rationale for R13 in

proposed TOP-001-3 states "The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements and how to adapt to conditions where processes, procedures, and automated software systems are not available (if used)". Thus, the actions needed on data quality are already expected in the Operating Plan to ensure the desired outcome. Therefore, a new requirement for data quality may be redundant.

In summary, it is appropriate to have an Operating Procedure to maintain and address quality of data used in Real-time Assessment. However, the monitoring and analysis of data quality for all data in Real-time is not practical and does not add value to reliability. Real-time Assessment tools used by TOPs have processes to manage bad data and provide valid results. Data quality should be monitored outside of the Real-time operator environment wherein staff other than System Operators can analyze patterns of data to identify data quality issues that truly impact Real-time analysis. The measures specified in TOP-010-1 indicate dated operator logs and voice recordings as evidence for compliance which will require the System Operator to monitor quality of all data. Also, the expectation of the System Operator to review data quality in Real-time for every data point is overkill.

TOP-010-1 R3 is redundant when compared to TOP-010-1 R6. R6 is requiring an indication of quality of analysis used in Real-time Assessment wherein R3 is requiring indication of quality of data used in Real-time Assessment. The quality of analysis used for Real-time Assessments may be an indicator of quality of data used in Real-time Assessment thus having a requirement on both is redundant and can result in multiple noncompliance incidents for a single problem. For example, a single bad Real-time data point may constitute a violation of TOP-010-1 R3 and since this data is used in Real-time Assessment it may also cause a violation of TOP-010-1 R6.

	ITC supports TOP-010-1 R7 having an independent processor to monitor Real-time alarm system because it provides value due to the heavy reliance on alarms by System Operators for situational awareness. However, the standard should specify if the unavailability of independent processor creates a violation of standard requirements. Although, the implementation plan of 12 months for R7 is unrealistic as compliance with this requirement may require entities to procure and implement new tools which is a lengthy process.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:	No
Answer Comment:	Texas RE recommends adding the Balancing Authority (BA) function to the applicability of R5 and R6. While it could be argued that a BA does not have to perform Real-time Assessments per a Reliability Standard requirement (in other words explicitly stated as required to do Real-time Assessments), its actions to maintain frequency are effectively as assessment based on Real-time data. Texas RE suggests using language from the rational to make TOP-010-1 R5 and R6 clearer. The requirements address “quality of analysis”, which could depend on many factors, while the rationale uses the language “to address issues related to the quality of the analysis inputs used for Real-time Assessments”. Texas RE recommends revising the phrase “with indication(s) of” used in

proposed TOP-10-1, R3, R4, and R6 as it is vague. The purpose of TOP-10-1, R3, R4, and R6 appears to be to ensure that the results of the required evaluations of potential Real-time data quality discrepancies are communicated to System Operators so that information regarding such data discrepancies could potentially be incorporated into Real-time monitoring, analysis functions, and Real-time assessments. Accordingly, registered entities should be required actually to provide the actual information from their data quality assessments to their System Operators. Texas RE would suggest substituting “relevant information and/or analyses concerning” for “with indication(s) of” to require appropriate, relevant information and/or any analyses of the quality of Real-time data be communicated to System Operators, not merely indications of data quality.

The reference to “with indications of” in the corresponding measures should also be revised along these lines. However, the types of evidence identified in the measures satisfy the proposed “relevant information and/or analyses concerning” standard.

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment: R4 states "Each Balancing Authority shall provide its System Operators with indication(s) of the quality of Real-time data necessary to perform its analysis functions and Real-time monitoring." Are the analysis functions limited to real-time analysis, or could this be interpreted to apply to study and after the fact analysis? We believe that this needs to be clear.

R5. What does "maintain the quality" mean? What if the quality of the analysis is not currently what it should be, then this requirement appears to preclude improving that quality.

R6 requires "indication(s) of the quality of any analysis"; how is quality defined? We believe this is very ambiguous as written and for us internal discussions resulted in multiple opinions. We believe that the term Quality needs to be concisely defined within the requirement.

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: No

Answer Comment: This standard is too vague and needs additional clarification. We support some of the comments from MRO.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments

Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: No

Answer Comment:

Southern believes that the criteria in R1.1 should be limited to the BA/TOP's ability to monitor and assess the current/expected condition of its BA/TOP area within the capabilities of its monitoring tools not including the criteria listed in R1.1.1-R1.1.4.

Each BA/TOP has the inherent responsibility to protect the integrity of the system in its BA/TOP area and to not contribute or cause any system violations in adjacent BA/TOP areas as required by other approved reliability standards. These already approved standards require the BA/TOP to continuously monitor the modeled facilities in its BA/TOP area and to accurately assess the state of the system using the information collected.

The BA/TOP is constantly evaluating the quality of data received to ensure it has an accurate state of system conditions to perform real time assessments. To impose a new standard focusing on data quality would only serve as administrative in nature and would not provide any substantial increases in reliability.

3. Do you agree with the Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

Summary Consideration

The SDT revised the proposed Implementation Plan based on stakeholder feedback. The proposed effective date is 18 months following regulatory approval for all requirements instead of the 12 months for some requirements and 18 months for the remainder as proposed in the initial draft Implementation Plan.

Specific comments and SDT responses are below:

- **Some commenters indicated that the proposed 12 and 18 month periods create confusion and suggested all requirements become effective 18 months following regulatory approval.** The SDT agrees and modified the proposed Implementation Plan accordingly.
- **Many commenters indicated that the implementation time was too short to allow EMS systems to be modified or procured. Commenters proposed various alternative periods up to 60 months.** Most recommendations for extended implementation periods cited a need to procure EMS systems based on rigid interpretations of requirements in the initial draft standard. The SDT believes the revised requirements in proposed IRO-018-1 and TOP-010-1 are clearer and implementable within the 18 month period and should not require procurement of new systems.
- **A commenter indicated the proposed implementation plan was too long because the capabilities are already well-established throughout the industry, and the reliability objectives should be addressed as quickly as possible.** Based on stake holder feedback and the SDT's experience, the SDT believes the proposed implementation period provides entities with necessary time to implement Operating Procedures or Processes and, if needed, upgrade functions of their Real-time monitoring and Real-time Assessment systems.

John Fontenot - Bryan Texas Utilities - 1 -	
Selected Answer:	Yes
Jeff Wells - Grand River Dam Authority - 3 -	

Selected Answer:	Yes
Thomas Foltz - AEP - 5 -	
Selected Answer:	No
Answer Comment:	AEP cannot determine the adequacy of the proposed implementation plan until more clarity is provided on the obligations themselves. If it is determined that the obligations *are* very granular (i.e. “per data point”), the implementation plans would be insufficient.
Leonard Kula - Independent Electricity System Operator - 2 -	
Selected Answer:	No
Answer Comment:	We do not agree with the need for the standard, and therefore do not agree with the proposed implementation plan.
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -	
Selected Answer:	Yes
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP	
Selected Answer:	No

Answer Comment: Xcel Energy feels that the implementation timeline is too short. We support the comments of the MRO NSRF recommending a 60 month implementation to allow entities adequate time to assess tools and complete necessary upgrades.

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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: No

Answer Comment:

The implementation plan is too short if entities need to specify, order and deploy new or modified Energy Management Systems (EMS) that can monitor, track, and report real-time data quality and availability in accordance with IRO-018 and TOP-010. Entities should be given an implementation plan with up to 60 months for new EMS software and systems.

The key is to allow entities the proper time to assess their tools and complete the right upgrades once. While prompt actions are good, forcing entities to assess, order, and deploy equipment in 12 or 18 months will lead to errors and possibly more risk of serious outages and problems in the short term.

The standard objective needs to be modified to a feasible reliability objective such as the assessment provides a reasonably high confidence interval that the system is in a reliable state. TOPs and BAs should be given much more time to make appropriate changes to their tools and EMS systems and to test their capabilities to detect and implement operating plans to respond to bad data detection and identification. The time needed to modify, specify, install, adjust and test systems or tool to meet the proposed standard should be, at a minimum, 3 to 5 years

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer: No

Answer Comment:	PJM does not support the proposed standards for the reasons noted in 1 and 2 above.	
Likes:	5	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph Long Island Power Authority, 1, Ganley Robert PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Darnez Gresham - Darnez Gresham On Behalf of: Thomas Mielnik, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3

Selected Answer:	No
Answer Comment:	The standard objective needs to be modified to a feasible reliability objective such as the assessment provides a reasonably high confidence interval that the system is in a reliable state. TOPs and BAs should be given much more time to make appropriate changes to their tools and EMS systems and to test their capabilities to detect and implement operating plans to respond to bad data detection and identification. The time needed to modify, specify, install, adjust and test systems or tool to meet the proposed standard should be, at a minimum, 3 to 5 years.

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

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: No

Answer Comment: Duke Energy is not in favor of the proposed 12 months and 18 months staggered implementation plan. In one of our previous comments, we requested that additional information be provided regarding the what is meant by the use of the terms alarm process monitor. If this alarm process monitor is something that would necessitate an entity to go out and procure something that is does not currently own, then additional time would be needed. The timeframe of 18 months for all requirements seems more appropriate.

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
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
Mark Schultz	City of Green Cove Springs	FRCC	3
Chris Adkins	City of Leesburg	FRCC	3
Ginny Beigel	City of Vero Beach	FRCC	9

Selected Answer: No

Answer Comment:

If TOP-003-3 is approved at the same time or after TOP-010-1, then the result of the implementation plan as drafted is that requirements to have quality data become effective at the same time as requirements that could cause the TOP and BA to be seeing new data for the first time. R5 of TOP-003-3 could result in a large volume of new data, so more time should be afforded to the receiving TOP and BA to become familiar with and begin utilizing that new data. We recommend the timeframes for **implementation of TOP-010-1 be modified to be 18 months and 24 months**, at a minimum, to allow for separation from TOP-003-3 R5. A section could be added that addresses a scenario where TOP-003-3 is approved well before TOP-010-1.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment: ***ATC supports the comments submitted by the MRO NSRF as it relates to TOP-010-1.***

The implementation plan is too short if entities need to specify, order and deploy new or modified Energy Management Systems (EMS) that can monitor, track, and report real-time data quality and availability in accordance with IRO-018 and TOP-010. Entities should be given an implementation plan with up to 60 months for new EMS software and systems.

The key is to allow entities the proper time to assess their tools and complete the right upgrades once. While prompt actions are good, forcing entities to assess, order, and deploy equipment in 12 or 18 months will lead to errors and possibly more risk of serious outages and problems in the short term.

Likes: 1 Grand River Dam Authority, 3, Wells Jeff

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer: Yes

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SERC,SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
John Allen	City Utilities Springfield Missouri	SPP	1,4
Darryl Boggess	Western Farmers Electric Cooperative	SPP	1,5
Donald Hargrove	Oklahoma Gas and Electric	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Robert Hirchak	CLECO	SPP	1,3,5,6
J. Scott Williams	City Utilities of Springfield Missouri	SPP	1,4
Sing Tay	Oklahom Gas and Electric	SPP	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5
Kyle McMenamin	Xcel Energy	SPP	1,3,5,6

Selected Answer: No

Answer Comment: Based on the proposed standards, 12 months should be sufficient time to simply develop a written procedure and ensure operators are knowledgeable. However, depending on what the final version of the standard looks like, it may be impossible to meet some of the resulting requirements unless systems are replaced. In that case, 36 months may be required.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Jack Stamper - Clark Public Utilities - 3 -

Selected Answer: Yes

Megan Wagner - Westar Energy - 6 -

Selected Answer: No

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: Project 2009-02

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Michael Forte	Con Edison	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2

Randy MacDonald	New Brunswick Power	NPCC	2
Kelly Dash	Con Edison	NPCC	3
Michael Jones	National Grid	NPCC	3
David Burke	Orange and Rockland Utilities	NPCC	3
Peter Yost	Con Edison	NPCC	4
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7

Selected Answer: Yes

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5

Selected Answer:	No
Answer Comment:	(1) The implementation plan is too short if entities need to specify, order, and deploy a new or modified Energy Management System (EMS) that can monitor, track, and report real-time data quality and availability in accordance with IRO-018 and TOP-010. Entities should be given an implementation plan with up to 60 months for new EMS software and infrastructure. (2) The key is to allow entities adequate time to assess their tools and complete the right upgrades once. While prompt actions are good, forcing entities to assess, order, and deploy equipment in 12 or 18 months will lead to errors and possibly more risk of serious outages and problems in the short-term. (3) In the alternative, if the SDT determines that it will not extend the implementation to 60 months, we ask the SDT to consider making all requirements effective after 18 months. Staggered effective dates has caused significant and unnecessary implementation issues, such as the confusion that occurred with implementing PRC-005 and its various requirements.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:	Yes

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:	Yes

Answer Comment:	Comments: ERCOT's comments above notwithstanding, the proposed implementation plan appears reasonable.

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer:	No
Answer Comment:	12 months may be too short depending on the capabilities of existing systems. More time may be needed to assess the existing capabilities of the EMS/SCADA system and if new systems are needed, time will be required to specify, order and deploy a new EMS system.

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:	No
Answer Comment:	ITC supports TOP-010-1 R7 having an independent processor to monitor Real-time alarm system because it provides value due to the heavy reliance on alarms by System Operators for situational awareness. However, the standard should specify if the unavailability of independent processor creates a violation of standard requirements. Although, the implementation plan of 12 months for R7 is unrealistic as compliance with this requirement may require entities to procure and implement new tools which is a lengthy process.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:	No
Answer Comment:	Texas RE is concerned the Implementation Plan allows for an increase in risk to the BES if quality is not already being addressed. To ensure reliable operations, Texas RE suggests decreasing the Implementation plan to a more reasonable time period such as the first day of the first quarter after approval for all requirements except R7, which requires TOPs and BAs to utilize an alarm process monitor. Twelve months is not an unreasonable time for the development of an independent alarm process monitor.

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:	Yes

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Answer Comment:	This standard is too vague and needs additional clarification. We support some of the comments from MRO.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: No

Answer Comment: Southern believes that the implementation date should be pushed back to allow time for the industry to determine the appropriate technology that is sufficient for each entity's operations. We also believe that in order to fully comply with the proposed standard, enough time should be allowed for the industry to update their current procedures and/or to create acceptable procedures, provide training to the appropriate System Operators and allow sufficient time for the entities to determine the technology available that is available and appropriate to support their operations, along with the required functionality.

4. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

Summary Consideration. VSL's have been revised in the proposed standards to incorporate stakeholder feedback and changes to the proposed requirements. The SDT has made use of levels as much as possible to describe varying degrees of compliance with the proposed requirements.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment: The team may want to consider using a more gradient-based approach for R1, R2, and R5, and using more than two VSL categories (driven by the number of elements not considered). If the requirements continue to use two VSL categories only, the High VSL should instead state "excluded at least one but not all of the elements…"

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment: **We do not agree with the need for the standard, and therefore do not agree with the proposed VRFs and VSLs.**

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer: Yes

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment: Xcel Energy believes that the proposed VSLs are not appropriate. The full spectrum of VSLs (Low/Med/High/Severe) should be utilized for each requirement, and that full clarification of what quantifies a violation at each severity level should be disseminated.

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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: No

Answer Comment:	The binary approach to the VSLs seems too severe. Suggest that the drafting team consider revising the VSLs to utilize moderate, high, and then severe if the entity missed one, two, three, or finally all data quality elements. R3 & R4: It is not clear from the wording of the single VSL level (which is Severe) if a violation of this Standard is incurred only if there are NO indications of quality of real-time data. If the meaning is to include situations where one or a few points with bad quality are missed (i.e., not notified to an operator) than assigning a Severe VSL seems inappropriate, and several levels of violations should be implemented. R6: Is it correct that a violation of this Standard is incurred only if there are NO indications provided to operators of poor quality of analysis results, and that missing some number of these instances is not a violation of this Standard? If the intent is to consider even a single miss a violation then assigning it a Severe VSL seems inappropriate, and several levels of violations should be implemented. R7: Is it correct that occasional failures of the independent alarm process monitor are not violations of this Standard? The standard objective needs to be modified to a feasible reliability objective such as the assessment provides a reasonably high confidence interval that the system is in a reliable state. Vague and unclear definitions will lead to significant audit discrepancies as to what appropriate measures are when it comes to implementation of operating processes/procedures.

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Likes:	5	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph Long Island Power Authority, 1, Ganley Robert PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer:	No
Answer Comment:	The VSL could be utilize to mitigate the compliance for R2 and other 24/7/365 requirements. The VSL for data quality could be stepped to percentage of points with bad quality, or duration. The most severe would be data quality that prevents the EMS from solving.

Darnez Gresham - Darnez Gresham On Behalf of: Thomas Mielnik, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3

Selected Answer:	No
Answer Comment:	The standard objective needs to be modified to a feasible reliability objective such as the assessment provides a reasonably high confidence interval that the system is in a reliable state. Vague and unclear definitions will lead to significant audit discrepancies as to what appropriate measures are when it comes to implementation of operating processes/procedures.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:	No
Answer Comment:	***ATC supports the comments submitted by the MRO NSRF as it relates to TOP-010-1.*** The binary approach to the VSLs seems too severe. Suggest that the drafting team consider revising the VSLs to utilize moderate, high, and then severe if the entity missed one, two, three, or finally all data quality elements. o R3 & R4: It is not clear from the wording of the single VSL level (which is Severe) if a violation of this Standard is incurred only if there are NO indications of quality of real-time data. If the meaning is to include situations where one or a few points with bad quality are missed (i.e., not notified to an operator) than assigning a Severe VSL seems inappropriate, and several levels of violations should be implemented. o R6: Is it correct that a violation of this Standard is incurred only if there are NO indications provided to operators of poor quality of analysis results, and that missing some number of these instances is not a violation of this Standard? If the intent is to consider even a single miss a violation then assigning it a Severe VSL seems inappropriate, and several levels of violations should be implemented. R7: Is it correct that occasional failures of the independent alarm process monitor are not violations of this Standard?
Likes:	1 Grand River Dam Authority, 3, Wells Jeff

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1 -

Selected Answer: No

Answer Comment: CenterPoint Energy feels the VSLs for R1, R2, and R5 do not match the intended meaning in the language of the Requirements (implementation). It appears the focus is more on exclusion of criteria during the development phase of Operating Processes and Procedures. CenterPoint Energy feels there are developmental phases of Operating Processes and Procedures and implantation phases, and perhaps the Requirements should be separated to reflect each. In doing so, the VSLs could and should be more balanced, in both instances, from Lower VSL to Severe VSL and not so heavily weighted for documentation deficiencies.

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SERC,SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
John Allen	City Utilities Springfield Missouri	SPP	1,4
Darryl Boggess	Western Farmers Electric Cooperative	SPP	1,5

Donald Hargrove	Oklahoma Gas and Electric	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Robert Hirchak	CLECO	SPP	1,3,5,6
J. Scott Williams	City Utilities of Springfield Missouri	SPP	1,4
Sing Tay	Oklahom Gas and Electric	SPP	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5
Kyle McMenamin	Xcel Energy	SPP	1,3,5,6

Selected Answer: No

Answer Comment: Could it not be a lower VSL for R1 on IRO-018-1 if only one element was missing, then a medium VSL if two elements were missing, then Severe if more than two were missing?

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Jack Stamper - Clark Public Utilities - 3 -

Selected Answer: Yes

Megan Wagner - Westar Energy - 6 -

Selected Answer: No

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: Project 2009-02

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Michael Forte	Con Edison	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
Kelly Dash	Con Edison	NPCC	3
Michael Jones	National Grid	NPCC	3
David Burke	Orange and Rockland Utilities	NPCC	3
Peter Yost	Con Edison	NPCC	4
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6

Alan Adamson	New York State Reliability Council	NPCC	7

Selected Answer: Yes

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5

Selected Answer: No

Answer Comment: The SDT should consider revising the VSLs to be on a graduated scale. Binary treatment of these requirements is improper and leads to higher dollar penalties for violations than are not commensurate with the risks to reliability.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment: Comments: As the proposed requirements in IRO-018 and TOP-010 are primarily administrative in nature, ERCOT does not support the approval of VSLs that are high and severe. Administrative requirements regarding operating processes should be considered a low VSL; alarming or other indicator activity should be considered for a VSL no higher than medium.

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: No

Answer Comment: Refer to comments submitted for question #3.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:	Texas RE recommends revising the VSLs for proposed IRO-18-001, R1 and TOP-10-1, R1 and R2. Specifically, the distinction between a High VSL and a Severe VSL for each of these requirements needs clarification as to how the use of subparts establishing the various required elements that must be included within the criteria for evaluating Real-time data quality discrepancies in Parts 1.1 and 2.1, respectively, will be addressed. The current VSLs for each of these three requirements could be read to assign only a High VSL to a registered entity that has: (1) only adopted one of the four required criteria elements in Part 1.1 (or Part 2.1 for TOP-10-1, R2) for evaluating potential Real-time data quality discrepancies; and (2) has not adopted any actions to coordinate the resolution of Real-time data quality discrepancies as required under Part 1.2 (or Part 2.2 for TOP-10-1, R2). For example, the High VSL category for TOP-10-1, R1 could potentially apply to a Registered Entity that adopts criteria for evaluating data outside of a prescribed data range, but fails to adopt similar criteria for analog data that is not updated within a predetermined time period, data entered manually to override telemetered information, data otherwise identified as invalid or suspect, as well as fails to specify any actions to coordinate the resolution of Real-time data quality discrepancies with the entity responsible for provide the data. Texas RE suggests a better approach would be to specify that a High VSL for proposed IRO-18-001, R1 and TOP-10-1, R1 and R2 would apply to Registered Entities that have failed to adopt one or more of the required criteria in Parts 1.1 or 2.1, respectively, or have failed to adopt actions to address Real-time data discrepancies as required in Parts 1.2 or 2.2, respectively. The Severe VSL category would then be reserved for instances in which a Registered Entity has failed to (1) adopt one or more of the required criteria for evaluating Real-time data quality discrepancies and (2) adopt actions to coordinate resolution of Real-time data quality discrepancies. To use the previous example regarding the VSLs for TOP-10-1, R1, a Registered Entity

	that adopts criteria for evaluating data outside of a prescribed data range, but fails to adopt similar criteria for analog data that is not updated within a predetermined time period, data entered manually to override telemetered information, data otherwise identified as invalid or suspect, as well as fails to specify any actions to coordinate the resolution of Real-time data quality discrepancies would now be subject to a Severe VSL. This approach would align the VSLs for IRO-18-001, R1 and TOP-10-1, R1 and R2 with the VSLs for other requirements in the proposed standards that do not have specifically required criteria elements. For example, under TOP-10-1, R5, the High VSL category applies to a Registered Entity if it does not establish (1) criteria for evaluating the quality of any analysis under in its Real-time assessments; or (2) actions to resolve quality deficiencies. In turn, the Severe VSL category under TOP-10-1, R5 is applicable to Registered Entity that has failed to both establish criteria for evaluating and actions to resolve quality deficiencies.

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:	No
Answer Comment:	**No, we ask to leave them as currently written for TOP-010-1 requirements.**

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:	Yes

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: No

Answer Comment: Southern believes that the VRFs and VSLs for the proposed standards are too high and should be modified.

5. Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.

Summary Consideration. The SDT thanks all commenters. Comments addressed in other sections are not duplicated here.

- **A commenter recommended combining proposed IRO-018-1 and TOP-010-1 into a single standard.** The proposed standards are intended to be consistent with the existing body of standards such that IRO standards apply to RCs and TOP standards apply to TOP and BAs.
- **A commenter indicated that the proposed standards should require monitoring of critical equipment.** Requirements to perform monitoring are addressed in other standards, such as IRO-002-2, IRO-003-2, proposed IRO-002-4, proposed TOP-001-3. Project 2009-02 is developing requirements to address the capabilities used by entities in performing Real-time monitoring and analysis.

- **A commenter asked how interrelationships between cybersecurity standards and requirements for performing monitoring and analysis are to be considered.** Applicable entities must consider cybersecurity standards and all other relevant NERC reliability standards in developing Operating Procedures and Operating Processes specified in the proposed standards. The SDT believes the requirements in the proposed standards do not detract from the ability of an applicable entity to comply with cybersecurity or any other standard.
- **A commenter asserted that requirements and measures for analysis quality in the proposed standard were vague and unenforceable. The commenter also questioned the ability of Regional Entities to enforce compliance of Reliability Coordinators.** The rationale box cited by the commenter has been revised to provide specific examples of types of analysis used applicable entities in performing Real-time Assessments. Additional detail related to this proposed requirement was added to the Guidelines and Technical Basis section. The SDT does not believe Regional Entities would be unable to enforce the proposed requirements in accordance with NERC Rules of Procedure.

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment: na

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment: na

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment: na

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment: na

Thomas Foltz - AEP - 5 -

Answer Comment: AEP has chosen to vote negative on TOP-010-1, primarily driven by our concerns of a) how granular the Requirements may be regarding the data points themselves and b) the impact of R1.2 on externally provided data. As previously stated, TOP-10-1 must be written in a reasonable manner that is able to accommodate the high volume of data points which continue to increase.

Leonard Kula - Independent Electricity System Operator - 2 -

Answer Comment: **Certification requirements are the appropriate place for mandating facilities and capabilities needed to perform reliability functions. These requirements can be enforced in a similar fashion as their reliability standard counterparts without de-certifying an entity if and when requirements are violated. We urge the drafting team, NERC, the Standards Committee and the regulators to think outside of the box and not let taking the right approach be bound by existing document framework.**

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Answer Comment: none

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Answer Comment: Xcel Energy suggests that the SDT clarifies what qualifies as "independent" in TOP-010-1 R7. Can this include a separate and independent process within the same EMS system?

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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: Suggest that the Standard Drafting team clarify that an independent alarm process monitor can be a separate and independent process within the same EMS system (R7). Therefore if an entity has a heartbeat monitor already integrated into its EMS system, the heartbeat monitor can be used. Independent doesn't necessarily mean an independent box / system completely separate from the EMS.

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Jonathan Appelbaum - United Illuminating Co. - 1 -

Answer Comment: This standard may establish an incentive for RC and TOP to limit the data they incorporate into the EMS since each point incorporated increases the compliance risk.

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:

Duke Energy requests clarification on the use of the time horizon Same Day Operations throughout the standard. How does the drafting team envision this time horizon corresponding with Real-time monitoring and assessments?

Andrew Pusztai - American Transmission Company, LLC - 1 -

Answer Comment:

ATC supports the comments submitted by the MRO NSRF as it relates to TOP-010-1.

Suggest that the Standard Drafting team clarify that an independent alarm process monitor can be a separate and independent process within the same EMS system (R7). Therefore if an entity has a heartbeat monitor already integrated into its EMS system, the heartbeat monitor can be used. Independent doesn't necessarily mean an independent box / system completely separate from the EMS.

Likes: 1 Grand River Dam Authority, 3, Wells Jeff

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1 -

Answer Comment: CenterPoint Energy has no additional comments.

Megan Wagner - Westar Energy - 6 -

Answer Comment: Westar supports the comments provided by the SPP RTO.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: Project 2009-02

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Michael Forte	Con Edison	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1

Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
Kelly Dash	Con Edison	NPCC	3
Michael Jones	National Grid	NPCC	3
David Burke	Orange and Rockland Utilities	NPCC	3
Peter Yost	Con Edison	NPCC	4
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7

Answer Comment:

Even though IRO-018-1 and TOP-010-1 are applicable to different functional entities, the contents are repetitive. It would be less cumbersome if one standard could be generated that would be applicable to all the functional entities.

Results based standards should focus on the “what” or objective opinions express by some are that the standard is overly prescriptive and could be more suited to a guideline document.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5

Selected Answer:

Answer Comment: We question the SDT's practice of posting the revised SAR along with the draft standard. It is unclear if the industry is to provide feedback about the removal of "analysis" from the SAR. This appears to be a substantive change to the project's scope.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment: Comments: ERCOT expresses concern that overly prescriptive requirements will hinder – not benefit – the processes and interactions occurring between functional entities currently as well as the continuous improvement of tools

	and associated capabilities. If the risk to be addressed is operator awareness of data and analysis quality issues and the taking of prompt action to resolve such issues, ERCOT recommends limited requirements that most directly address these risks. Overly prescriptive requirements that hinder tool and analyses improvement and the free-flow of functional entity communications that are already occurring do not benefit reliability. Further, the complicated nature of data exchange, inputs, and analyses require coordination and cooperation amongst many registered entities. Without a reciprocal obligation by other entities to facilitate responsiveness when an issue arises, the proposed standards and requirements will not achieve their intended objective. Until such obligation is included in the proposed standard, ERCOT is unable to support its approval. This reciprocal obligation is critical for achieving the implied objective of the proposed standard because – even where a Reliability Coordinator initiates resolution of issues quickly – lack of responsiveness by the entity that is situated to address an issue will prevent effective, efficient resolution.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:	Texas RE recommends reviewing references in the Evidence Retention section of TOP-010-1. There is reference to R5 and R6 having a rolling 30 day period for evidence. It would seem that is an incorrect reference as R5 requires implementation of a Process or Procedure. The 30-day period is short of a timeframe and is not supported by industry practice. Similar statement for IRO-018-1 except it references R3 and R4. R3 is a requirement to implement a procedure. The SDT may have been trying to capture the quality of data indication requirements in each of the Standards. In TOP-010-1, why is the data retention for a BA different from that for a TOP (relates to the incorrect reference but if the reference is corrected this issue goes away)?
David Jendras - Ameren - Ameren Services - 3 -	
Selected Answer:	
Answer Comment:	In our opinion, clarity is needed throughout the proposed standards so that entities will not be confused over how the requirements will be audited.

Additional Comments Submitted by William R. Harris for the Foundation For Resilient Societies, Inc.:

The Foundation for Resilient Societies, Inc. supports "reliability standards" that are designed to improve the reliability of the bulk electric system. We supported the near-real-time monitoring initiative for critical equipment, "Project 2012-01 Equipment Monitoring and Diagnostic Devices." Unfortunately, the NERC Standards Committee moved to cancel this project at their June 5, 2013 meeting and this cancellation was later approved by the NERC Board of Trustees. During the period when no NERC monitoring project was in process, Generator Operators used the potential lack of "visibility" during solar geomagnetic disturbances (GMD) to seek and obtain exemption from NERC Standard EOP-010-1 — Geomagnetic Disturbance Operations. This imprudent exemption increased risks to large power transformers in the bulk power system.

The present revival of a NERC real-time monitoring standard has potential to improve equipment monitoring and system reliability. But the lack of metrics or boundary conditions for equipment or events requiring real-time monitoring undermines the prospective benefits of this proposed standard. Without metrics, how can measures such as "dated operator or supporting logs, dated checklists, voice recordings (or other evidence)" be evaluated?

There are no connections between these processes and/or procedures for monitoring reliability or performing analysis, on the one hand, and cybersecurity standards, on the other hand. The latter critically affects reliability. How are these interrelationships to be considered?

The term "quality" as used 23 times in the standard is a very general term. Its composition is affected by hundreds of factors in instrumentation, pre-Reliability Coordinator processing, etc. Can reliability even be determined in the absence of a grid-wide standard for data flows?

The rationale for R3 and R4 asserts that "operators have procedures and receive indication(s) to address issues related to the quality of the analysis inputs used for Real-time Assessments." How can such a vague process be judged compliant or non-compliant? The measurement examples cited in M2, "computer printouts" (of what?) and system specifications (what "systems"?), are so non-deterministic as to be meaningless in judging quality of analysis.

Compliance would be nearly non-enforceable for these vague reliability monitoring and analytic assessments. How is NERC planning on enforcing compliance particularly when most Reliability Coordinators (RC) are also the Regional Entity? In almost every case, the RC has no evidence to support compliance with these unmeasurable, metric-less requirements as prescribed in this set of standards.

Significantly, the draft standard does not require monitoring of critical equipment such as large power transformers, generators, or reactive power support devices. Instead, the standard takes the approach of requiring monitoring of the "quality" of whatever data flows might exist. A good way to minimize compliance costs with this standard would be to simply eliminate data flows from critical equipment.

Overall, the Standard Drafting Team needs to be more specific and more rigorous. Otherwise, a vague standard will leave the false impression that real-time monitoring requirements exist; whereas, in reality, the standard will provide an escape hatch for equipment monitoring requirements, resulting in net harm to reliability of the bulk power system.

End of Report

Standard Development Timeline

This drafting team maintained this section while developing the standard. It will be removed when the standard becomes effective.

Description of Current Draft

This draft is the second posting of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	July 16 - August 17, 2015
45-day formal comment period with initial ballot	September 24 - November 9, 2015

Anticipated Actions	Date
45-day formal comment period with additional ballot	December 2015
10-day final ballot	February 2016
NERC Board (Board) adoption	May 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:** **Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **IRO-018-1**
3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirement R1: The Reliability Coordinator (RC) uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform Real-time monitoring and Real-time Assessments appear in other standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the RC shall include actions to resolve Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. These actions could be the same as the process used to resolve data conflicts required by IRO-010-2 Requirement R3 Part 3.2 provided that this process resolves Real-time data quality issues.

The revision in Part 1.3 to resolve Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R1. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator or supporting logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R2: Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

R2. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

2.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

2.3. Actions to resolve analysis quality issues affecting its Real-time Assessments.

M2. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R2. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R3: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

R3. Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Reliability Coordinator shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 it was compliant for the full-time period since the last audit.

The Reliability Coordinator 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 Reliability Coordinator shall retain evidence of compliance for Requirements R1 and R3 and Measures M1and M3 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall retain evidence of compliance for Requirement R2 and Measure M2 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator 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 Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes 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 Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of

		analysis used in its Real-time Assessments did not include one of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include two of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.
R3.	N/A	N/A	The Reliability Coordinator has an alarm process monitor but the alarm process monitor did not provide a notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The Reliability Coordinator does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO standards. As used in TOP and IRO standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring includes the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The RC uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform monitoring and Real-time Assessments appear in other standards.

The RC's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed IRO-018-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, such as:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the RC shall include actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to resolve data quality issues in an appropriate timeframe.

Requirement R2

Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards. Examples of the types of analysis used in Real-time

Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The entity must use appropriate quality criteria based on the analysis capabilities used to perform Real-time Assessments, such as solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R3

Requirement R3 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. A stalled Real-time monitoring alarm processor must not cause a failure of the alarm process monitor.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon NERC Board of Trustees 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~~maintained this section while developing the standard~~ and~~. It will be removed when the standard becomes effective.

Description of Current Draft

This draft is the ~~first~~second posting of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	July 16 - August 17, 2015
45-day formal comment period with initial ballot	September 24 - November 9, 2015

Anticipated Actions	Date
~~45-day formal comment period with initial ballot~~	~~September 2015~~
45-day formal comment period with additional ballot	December 2015
10-day final ballot	~~January~~February 2016
NERC Board (Board) adoption	~~February~~May 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:** **Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **IRO-018-1**
3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities ~~used by Reliability Coordinator System Operators in support of~~to support reliable System operations.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

> **Rationale for Requirement R1:** The Reliability Coordinator (RC) uses a set of Real-time data identified in ~~approved standard~~ IRO-010-1a Requirement R1 and~~ proposed standard~~ IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform Real-time monitoring and Real-time Assessments appear in other standards.
>
> The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.
>
> Requirement R1 Part 1.~~2~~3 of this standard specifies the RC shall include actions to ~~coordinate resolution of~~resolve Real-time data quality ~~discrepancies~~issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. These actions could be the same as the process used to resolve data conflicts required by IRO-010-2 Requirement R3 Part 3.2, provided that this process ~~could~~resolves Real-time data quality issues.
>
> The revision in Part 1.3 to resolve Real-time data quality issues~~.~~ *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R1. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating

Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: ~~Same Day Operations,~~ Real-time Operations]*

1.1. Criteria for evaluating ~~potential~~the quality of Real-time data ~~quality discrepancies including, but not limited~~;

~~**1.1.1.** Data outside of a prescribed data range;~~

~~**1.1.2.** Analog data not updated within a predetermined time period;~~

~~**1.1.3.** Data entered manually to override telemetered information; and~~

~~**1.1.1.** Data otherwise identified as invalid or suspect~~.

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

~~**1.2.**~~**1.3.** Actions to resolve ~~coordinate resolution of~~Real-time data quality ~~discrepancies~~issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Proce~~dure~~ss or Operating Proce~~ss~~dure in electronic or hard copy format meeting all provisions of Requirement R1~~,~~; and 2) evidence the Reliability Coordinator implemented the Operating Proce~~dure~~ss or Operating Proce~~ss~~dure as called for in the Operating Proce~~dure~~ss or Operating Proce~~ss~~dure, such as dated operator or supporting logs, dated checklists, voice recordings, voice transcripts, or other evidence.

~~**R2.** Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*~~

~~**M2.** Each Reliability Coordinator shall have evidence it provided its System Operators with indications of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to, computer printouts, system specifications, or other evidence.~~

Rationale for ~~Requirements R3 and R4:~~ ~~Requirements R3 and R4 ensure the RC's System Operators~~**Requirement R2:** Requirement R2 ensures RCs have procedures ~~and receive indication(s)~~ to address issues related to the quality of the analysis ~~inputs~~results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

~~R3.~~R2. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to ~~maintain~~address the quality of ~~any~~ analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: ~~Same Day Operations,~~ Real-time Operations]*

2.1. Criteria for evaluating the quality of ~~any~~analysis used in its Real-time Assessments;

~~3.1.~~2.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

~~3.2.~~2.3. Actions to resolve ~~quality deficiencies in any~~ analysis ~~used in~~quality issues affecting its Real-time Assessments.

~~M3.~~M2. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to ~~maintain~~address the quality of ~~any~~ analysis used in its Real-time Assessments~~.~~ as specified in Requirement R2. This evidence could include, but is not limited to: 1) an Operating Proce~~dure~~ss or Operating Proces~~s~~dure in electronic or hard copy format meeting all provisions of Requirement ~~R3,~~R2; and 2) evidence the Reliability Coordinator implemented the Operating Proce~~dure~~ss or Operating Proces~~s~~dure as called for in the Operating Proce~~dure~~ss or Operating Proces~~s~~dure , such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

~~**R4.** Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*~~

~~Each Reliability Coordinator shall have evidence it provided its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.~~

Rationale for Requirement ~~R5~~R3: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

~~An~~The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor ~~is one that would~~must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor. ~~A 'heartbeat' or 'watchdog' monitoring system may accomplish this objective.~~

~~R5.~~R3. Each Reliability Coordinator shall ~~utilize~~have an ~~independent~~ alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: ~~Same Day Operations,~~ Real-time Operations]*

~~M4.~~M3. Each Reliability Coordinator shall have evidence ~~it utilized~~of an ~~independent~~ alarm process monitor that provide~~d~~s notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 it was compliant for the full-time period since the last audit.

The Reliability Coordinator 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 Reliability Coordinator shall retain evidence of compliance for Requirements R1~~, R2,~~ and ~~R5~~R3 and Measures ~~M1, M2, and M5~~M1and M3 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ~~ninety~~90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall retain evidence of compliance for ~~Requirements R3~~Requirement R2 and ~~R4 and Measures M3 and M4~~Measure

M2 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator 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 Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes 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 Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include ~~one~~two of the elements listed in Part 1.1 ~~and~~through Part 1.~~2.~~3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 ~~and~~through Part 1.~~2~~3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
~~**R2.**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not provide its System Operators with indication(s)~~

				~~of the quality of Real-time data used to perform its Real-time monitoring and Real-time Assessments.~~
~~R3~~R2.	N/A	~~N/A~~The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 2.1 through Part 2.3.	The Reliability Coordinator's Operating Process or Operating Procedure to ~~maintain~~address the quality of ~~any~~ analysis used in its Real-time Assessments did not include ~~one~~two of the elements listed in Part ~~3~~2.1 ~~and~~through Part 2.3~~.2.~~	The Reliability Coordinator's Operating Process or Operating Procedure to ~~maintain~~address the quality of ~~any~~ analysis used in its Real-time Assessments did not include any of the elements listed in Part ~~3~~2.1 ~~and~~through Part 2.3~~.2~~; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to ~~maintain~~address the quality of ~~any~~ analysis used in its Real-time Assessments.
~~R4.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.~~

~~R5~~R3.	N/A	N/A	~~N/A~~The Reliability Coordinator has an alarm process monitor but the alarm process monitor did not provide a notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The Reliability Coordinator ~~did~~does not ~~utilize~~have an ~~independent~~ alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by ~~existing and proposed~~ TOP and IRO standards. As used in TOP and IRO standards, monitoring involves observing operating status and operating ~~value(s)~~values in Real-time for awareness of system conditions. Real-time monitoring includes the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The RC uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform monitoring and Real-time Assessments appear in other standards.

The RC's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed IRO-018-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, such as:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the RC shall include actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to resolve data quality issues in an appropriate timeframe.

Requirement R2

Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards. Examples of the types of analysis used in Real-time

Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The entity must use appropriate quality criteria based on the analysis capabilities used to perform Real-time Assessments, such as solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R3

Requirement R3 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. A stalled Real-time monitoring alarm processor must not cause a failure of the alarm process monitor.

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~~NERC Board of Trustees adoption, the text from the rationale text boxes ~~was~~will be moved to this section.

Standard Development Timeline

This drafting team maintained this section while developing the standard. It will be removed when the standard becomes effective.

Description of Current Draft

This draft is the second posting of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	July 16 - August 17, 2015
45-day formal comment period with initial ballot	September 24 - November 9, 2015

Anticipated Actions	Date
45-day formal comment period with additional ballot	December 2015
10-day final ballot	February 2016
NERC Board (Board) adoption	May 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:** **Real-time Reliability Monitoring and Analysis Capabilities**

2. **Number:** **TOP-010-1**

3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Operators

   4.1.2. Balancing Authorities

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirement R1: The Transmission Operator (TOP) uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform Real-time monitoring and Real-time Assessments appear in other standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the TOP shall include actions to resolve Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. These actions could be the same as the process used to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2, provided that this process resolves Real-time data quality issues.

The revision in Part 1.3 to resolve Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R1. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Transmission Operator shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R2: The Balancing Authority (BA) uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 of this standard specifies the BA shall include actions to resolve Real-time data quality issues affecting its analysis functions in its Operating Process or Operating Procedure. These actions could be the same as the process to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2 provided that this process resolves Real-time data quality issues.

The revision in Part 2.3 to resolve Real-time data quality issues *when data quality affects its analysis functions* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R2. Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. Criteria for evaluating the quality of Real-time data;

2.2. Provisions to indicate the quality of Real-time data to the System Operator; and

2.3. Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.

M2. Each Balancing Authority shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Balancing Authority implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R3: Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

R3. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

3.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

3.3. Actions to resolve analysis quality issues affecting its Real-time Assessments.

M3. Each Transmission Operator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R3. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R3; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R4: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

R4. Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Transmission Operator and Balancing Authority shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 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 applicable entity shall retain evidence of compliance for Requirements R1, R2, and R4, and Measures M1, M2, and M4 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall retain evidence of compliance for Requirement R3 and Measure M3 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity 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.

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 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 Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the

		Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include two of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.
R3.	N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 through Part 3.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of

				analysis used in its Real-time Assessments.
R4.	N/A	N/A	The responsible entity has an alarm process monitor but the alarm process monitor did not provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The responsible entity does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO standards. As used in TOP and IRO standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring includes the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The TOP uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform monitoring and Real-time Assessments appear in other standards.

The TOP's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, such as:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the TOP shall include actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to resolve data quality issues in an appropriate timeframe.

Requirement R2

The BA uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other standards.

The BA's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R2 Part 2.1. The criteria supports identification of applicable data quality issues, such as:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 specifies the BA shall include in its Operating Process or Operating Procedure actions to resolve Real-time data quality issues when data quality affects its analysis functions. The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the analysis quality so that effective actions can be taken to resolve data quality issues in an appropriate timeframe.

<u>Requirement R3</u>

Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The entity must use appropriate quality criteria based on the analysis capabilities used to perform Real-time Assessments, such as solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

<u>Requirement R4</u>

Requirement R4 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. A stalled Real-time monitoring alarm processor should not cause a failure of the alarm process monitor.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon NERC Board of Trustees 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~~maintained this section while developing the standard ~~and~~. It will be removed when the standard becomes effective.

Description of Current Draft

This draft is the ~~first~~second posting of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	July 16 - August 17, 2015
45-day formal comment period with initial ballot	September 24 - November 9, 2015

Anticipated Actions	Date
~~45-day formal comment period with initial ballot~~	~~September 2015~~
45-day formal comment period with additional ballot	December 2015
10-day final ballot	~~January~~February 2016
NERC Board (Board) adoption	~~February~~May 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:** **Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **TOP-010-1**
3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities ~~used by System Operators in~~to support ~~of~~ reliable System operations.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1. Transmission Operators
   4.1.2. Balancing Authorities
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirement R1: The Transmission Operator (TOP) uses a set of Real-time data identified in ~~proposed standard~~ TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform Real-time monitoring and Real-time Assessments appear in other standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.~~2~~3 of this standard specifies the TOP shall include actions to ~~coordinate resolution of~~resolve Real-time data quality ~~discrepancies~~issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. These actions could be the same as the process used to resolve data conflicts required by ~~proposed~~ TOP-003-3 Requirement R5 Part 5.2 provided that this process ~~could~~resolves Real-time data quality issues.

The revision in Part 1.3 to resolve Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R1. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating

Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: ~~Same Day Operations,~~ Real-time Operations]*

1.1. Criteria for evaluating ~~potential~~the quality of Real-time data ~~quality discrepancies including, but not limited~~;

~~**1.1.1.** Data outside of a prescribed data range;~~

~~**1.1.2.** Analog data not updated within a predetermined time period;~~

~~**1.1.3.** Data entered manually to override telemetered information; and~~

~~**1.1.1.** Data otherwise identified as invalid or suspect.~~

1.2. Provisions to~~:~~ indicate the quality of Real-time data to the System Operator; and

1.3. Actions to ~~coordinate resolution of~~resolve Real-time data quality ~~discrepancies~~issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Transmission Operator shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time ~~M~~monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Proce~~dure~~ss or Operating Proce~~ss~~dure in electronic or hard copy format meeting all provisions of Requirement R1~~,~~; and 2) evidence the Transmission Operator implemented the Operating Proce~~dure~~ss or Operating Proce~~ss~~dure as called for in the Operating Proce~~dure~~ss or Operating Proce~~ss~~dure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R2: The Balancing Authority (BA) uses a set of Real-time data identified in ~~proposed standard~~ TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.~~2~~3 of this standard specifies the BA shall include actions to ~~coordinate resolution of~~resolve Real-time data quality ~~discrepancies~~issues affecting its analysis functions in its Operating Process or Operating Procedure. These actions could be the same as the process to resolve data conflicts required by ~~proposed~~ TOP-003-3 Requirement R5 Part 5.2 provided that this process ~~could~~ resolves Real-time data quality issues.

The revision in Part 2.3 to resolve Real-time data quality issues *when data quality affects its analysis functions* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R2. Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: ~~Same Day Operations,~~ Real-time Operations]*

2.1. Criteria for evaluating ~~potential~~the quality of Real-time data~~ quality discrepancies including, but not limited~~;

~~**2.1.1.** Data outside of a prescribed data range;~~

~~**2.1.2.** Analog data not updated within a predetermined time period;~~

~~**2.1.3.** Data entered manually to override telemetered information; and~~

~~**2.1.1.** Data otherwise identified as invalid or suspect.~~

2.2. Provisions to~~:~~ indicate the quality of Real-time data to the System Operator; and

2.3. ~~2.2~~Actions to ~~coordinate resolution of~~resolve Real-time data quality ~~discrepancies~~issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.

M2. Each Balancing Authority shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to: 1) an Operating Proce~~dure~~ss or Operating Proce~~ss~~dure in electronic or hard copy format meeting all provisions of Requirement R2~~,~~; and 2) evidence the Balancing Authority implemented the Operating Proce~~dure~~ss or Operating Proce~~ss~~dure as called for in the Operating Proce~~dure~~ss or Operating Proce~~ss~~dure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

~~**R3.** Each Transmission Operator shall provide its System Operators with indication(s) of the quality of Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*~~

~~**M3.** Each Transmission Operator shall have evidence it provided its System Operators with indications of the quality of Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to, computer printouts, system specifications, or other evidence.~~

~~**R4.** Each Balancing Authority shall provide its System Operators with indication(s) of the quality of Real-time data necessary to perform its analysis functions and Real-time monitoring. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*~~

~~**M4.** Each Balancing Authority shall have evidence it provided its System Operators with indications of the quality of Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to, computer printouts, system specifications, or other evidence.~~

Rationale for ~~Requirements R5 and R6:~~ ~~Requirements R5 and R6 ensure the TOP's System Operators~~**Requirement R3:** Requirement R3 ensures TOPs have procedures ~~and receive indication(s)~~ to address issues related to the quality of the analysis ~~inputs~~results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

~~R5.~~R3. Each Transmission Operator shall implement an Operating Process or Operating Procedure to ~~maintain~~address the quality of ~~any~~ analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: ~~Same Day Operations,~~ Real-time Operations]*

3.1. Criteria for evaluating the quality of ~~any~~analysis used in its Real-time Assessments;

~~5.1.~~3.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

~~5.2.~~3.3. Actions to resolve ~~quality deficiencies in any~~ analysis ~~used in~~quality issues affecting its Real-time Assessments.

~~M5.~~M3. Each Transmission Operator shall have evidence it implemented its Operating Process or Operating Procedure to ~~maintain~~address the quality of ~~any~~ analysis used in its Real-time Assessments~~.~~ as specified in Requirement R3. This evidence could include, but is not limited to: 1) an Operating Proce~~dure~~ss or Operating Proce~~ss~~dure in electronic or hard copy format meeting all provisions of Requirement ~~R5,~~R3; and 2) evidence the Transmission Operator implemented the Operating Proce~~dure~~ss or Operating Proce~~ss~~dure as called for in the Operating Proce~~dure~~ss or Operating Proce~~ss~~dure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

~~**R6.** Each Transmission Operator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*~~

~~**M6.** Each Transmission Operator shall have evidence it provided its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessment capabilities. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.~~

> **Rationale for Requirement ~~R7~~R4:** The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.
>
> ~~An~~The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor ~~is one that would~~must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor. ~~A 'heartbeat' or 'watchdog' monitoring system may accomplish this objective.~~

~~R7.~~R4. Each Transmission Operator and Balancing Authority shall ~~utilize~~have an ~~independent~~ alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: ~~Same Day Operations,~~ Real-time Operations]*

~~M7.~~M4. Each Transmission Operator and Balancing Authority shall have evidence ~~it utilized~~of an ~~independent~~ alarm process monitor that provide~~d~~s notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 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 applicable entity shall retain evidence of compliance for Requirements R1 ~~through~~, R2, and R4, and ~~Requirement R7, and~~ Measures M1~~ through M4~~, M2, and ~~Measure M7,~~M4 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ~~ninety~~90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall retain evidence of compliance for ~~Requirements R5 and R6 and Measures M5 and M6~~Requirement R3 and Measure M3 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity 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.

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 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 Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include ~~one~~two of the elements listed in Part 1.1 ~~and~~through Part 1.~~2.~~3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 ~~and~~through Part 1.~~2~~3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	~~N/A~~The Balancing Authority's Operating Process or Operating	The Balancing Authority's Operating Process or Operating Procedure to	The Balancing Authority's Operating Process or Operating Procedure to

		Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 through Part 2.3.	address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include ~~one~~two of the elements listed in Part 2.1 ~~and~~through Part 2.~~2.~~3.	address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 ~~and~~through Part 2.~~2~~3; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.
~~**R3.**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its Real-time monitoring and Real-time Assessments.~~
~~**R4.**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its~~

				~~analysis functions and Real-time monitoring.~~
~~R5~~R3.	N/A	~~N/A~~The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to ~~maintain~~address the quality of ~~any~~ analysis used in its Real-time Assessments did not include ~~one~~two of the elements listed in Part ~~5~~3.1 ~~and~~through Part ~~5.2~~3.3.	The Transmission Operator's Operating Process or Operating Procedure to ~~maintain~~address the quality of ~~any~~ analysis used in its Real-time Assessments did not include any of the elements listed in Part ~~5~~3.1 ~~and~~through Part ~~5.2~~3.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to ~~maintain~~address the quality of ~~any~~ analysis used in its Real-time Assessments.
~~R6.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.~~
~~R7~~R4.	N/A	N/A	~~N/A~~The responsible entity has an alarm process monitor but the alarm	The responsible entity ~~did~~does not ~~utilize~~have an ~~independent~~ alarm process

			process monitor did not provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by ~~existing and proposed~~ TOP and IRO standards. As used in TOP and IRO standards, monitoring involves observing operating status and operating ~~value(s)~~values in Real-time for awareness of system conditions. Real-time monitoring includes the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The TOP uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform monitoring and Real-time Assessments appear in other standards.

The TOP's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, such as:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the TOP shall include actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to resolve data quality issues in an appropriate timeframe.

Requirement R2

The BA uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other standards.

The BA's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R2 Part 2.1. The criteria supports identification of applicable data quality issues, such as:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 specifies the BA shall include in its Operating Process or Operating Procedure actions to resolve Real-time data quality issues when data quality affects its analysis functions. The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the analysis quality so that effective actions can be taken to resolve data quality issues in an appropriate timeframe.

Requirement R3

Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The entity must use appropriate quality criteria based on the analysis capabilities used to perform Real-time Assessments, such as solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must include~~s~~ provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R4

Requirement R4 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. A stalled Real-time monitoring alarm processor should not cause a failure of the alarm process monitor.

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~~NERC Board of Trustees adoption, the text from the rationale text boxes ~~was~~will be moved to this section.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Requested Approvals

- IRO-018-1 - Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
- TOP-010-1 - Real-time Reliability Monitoring and Analysis Capabilities

Requested Retirements

- None

Prerequisite Approval

Rationale: Due to regulatory approval of TOP-003-3, the prerequisite approval from the initial draft Implementation Plan has been satisfied.

- None

Revisions to Defined Terms in the NERC Glossary

None

Applicable Entities

- Reliability Coordinators
- Transmission Operators
- Balancing Authorities

Effective Date

Rationale: The Implementation Plan has been revised and simplified such that all requirements become effective 18 months following regulatory approval. The implementation period provides entities time to implement Operating Processes or Operating Procedures and enhance functions of their Real-time monitoring systems, as necessary.

IRO-018-1

- All Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, all Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

TOP-010-1

- All Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, all Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

NERC
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RELIABILITY CORPORATION

Implementation Plan

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Requested Approvals

- IRO-018-1 - Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
- TOP-010-1 - Real-time Reliability Monitoring and Analysis Capabilities

Requested Retirements

- None

Prerequisite Approval

- ~~TOP-003-3 Operational Reliability Data~~

~~Proposed~~

Rationale: Due to regulatory approval of TOP-003-3, the prerequisite approval from the initial draft Implementation Plan has been satisfied.

- None

~~*TOP-010-1* contains requirements addressing the quality of data necessary for Transmission Operators and Balancing Authorities to perform Real-time monitoring and analysis functions. Requirements for specifying and providing this data appear in TOP-003-3. Accordingly, proposed TOP-010-1 cannot become effective prior to TOP-003-3.~~

Revisions to Defined Terms in the NERC Glossary

None

Applicable Entities

- Reliability Coordinators
- Transmission Operators
- Balancing Authorities

Effective Date

Rationale: The Implementation Plan has been revised and simplified such that all requirements become effective 18 months following regulatory approval. The implementation period provides entities time to implement Operating Processes or Operating Procedures and enhance functions of their Real-time monitoring systems, as necessary.

IRO-018-1

- All Requirements ~~R1, R2, and R5~~ shall become effective on the first day of the first calendar quarter that is ~~12~~18 months after the date that this 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, all Requirements ~~R1, R2, and R5~~ shall become effective on the first day of the first calendar quarter that is ~~12~~18 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

TOP-010-1

- All Requirements ~~R3 and R4~~ shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, all Requirements ~~R3 and R4~~ shall become effective on the first day of the first calendar quarter that is ~~twelve~~18 months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

~~***TOP-010-1***~~

~~***If the prerequisite approval occurs on or before approval of the standards in Project 2009-02:***~~

- ~~Requirements R1, R2, R3, R4, and R7 shall become effective on the first day of the first calendar quarter that is 12 months after the date that this 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, Requirements R1, R2, R3, R4, and R7 shall become effective on the first day of the first calendar quarter that is 12 months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~
- ~~Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~***If the prerequisite approval occurs after approval of the standards in Project 2009-02:***~~

- ~~Requirements R1, R2, R3, R4, and R7 shall become effective on the first day of the first calendar quarter that is 12 months after the date that TOP-003-3 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, Requirements R1, R2, R3, R4, and R7 shall~~

~~become effective on the first day of the first calendar quarter that is 12 months after the date TOP-010-1 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date that TOP-003-3 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, Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date TOP-010-1 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

Unofficial Comment Form

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities IRO-018-1 and TOP-010-1

DO NOT use this form for submitting comments. Use the electronic form to submit comments on IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities and TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities. The electronic comment form must be completed by **8 p.m. Eastern, Monday, January 25, 2016**.

Documents and information about this project are available on the project page. If you have any questions, contact Standards Developer, Mark Olson (via email), or at (404) 446-9760.

Background Information

Project 2009-02 Real-time Monitoring and Analysis Capabilities originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). The project SAR was revised earlier this year to account for revisions to TOP and IRO standards developed in Project 2014-03. Project 2009-02 is developing requirements to address monitoring and analysis capability issues identified in the 2008 RTBPTF report and the 2011 Southwest Outage Report, as well as addressing FERC Order No. 693 directives.

The Standard Drafting Team (SDT) has revised the two draft Reliability Standards in response to stakeholder comments from the initial posting. IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities addresses issues related to the quality and availability of Reliability Coordinator (RC) monitoring and analysis capabilities. TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities contains proposed requirements for Transmission Operators (TOPs) and Balancing Authorities (BAs).

Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. Do you agree with the changes made by the SDT to draft standard IRO-018-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

☐ Yes
☐ No
Comments:

2. Do you agree with the changes made by the SDT to draft standard TOP-010-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

☐ Yes
☐ No
Comments:

3. Do you agree with the revised Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

☐ Yes
☐ No
Comments:

4. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

☐ Yes
☐ No
Comments:

5. Provide any additional comments for the SDT to consider, if desired.
Comments:

Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	Project 2009-02: Real-time Reliability Monitoring and Analysis Capabilities		
Date Submitted:	June 18, 2015		
SAR Requester Information			
Name:	Saad Malik		
Organization:	Peak Reliability		
Telephone:	970.776.5635	E-mail:	smalik@peakrc.com
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
To establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations.
Industry Need (What is the industry problem this request is trying to solve?):
According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* dated April 2004 (2003 Blackout Report), a principal cause of the August 14 blackout was a lack of situational awareness. Recommendation 22 of the 2003 Blackout Report states that the industry should "evaluate and adopt better Real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate Real-time tools and their usage within the industry. The Task Force produced the report *Real-Time Tools Survey Analysis and Recommendations* dated March 13, 2008 (RTBPTF Report)

SAR Information
that included recommendations for the functionality, performance, and management of Real-time tools. The FERC and NERC Staff Report *Arizona-Southern California Outages on September 8, 2011* (2011 Southwest Outage Report) also cited weaknesses in Real-time situational awareness and recommended improvements in Real-time monitoring and analysis capabilities. In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to System operators: • P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.* • P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.* • P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.* This SAR addresses the event reports, Order No. 693 directives, and recommendations from the RTBPTF Report that have not been addressed in other standards projects. The SAR Drafting Team also conducted a Technical Conference on June 4, 2015 to obtain stakeholder input on reliability objectives to be addressed in the proposed project.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Standards Drafting Team (SDT) shall develop requirements and definition(s), as needed, for Real-time monitoring and analysis capabilities to ensure effective operator situational awareness. The project will address recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Situational awareness of Real-time system operations is enabled through monitoring and analysis tasks performed by operators. Existing and proposed TOP and IRO standards and definitions developed in

SAR Information
Project 2014-03 Revisions to TOP and IRO Standards require Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed project will provide additional reliability benefits by addressing issues with the availability and information quality of Real-time monitoring and analysis capabilities. Specifically, the SDT will develop requirements and definition(s), as needed, to accomplish the following: • Establish a common understanding of *monitoring* as it applies to Real-time situational awareness of the Bulk Electric System (BES), • Provide operators with indication(s) of the quality of information being provided by *monitoring* capabilities and procedure(s) to address data quality issues, • Provide operators with notification(s) during unplanned loss of *monitoring* capabilities, and • Provide operators with indication(s) of the quality of information being provided by *analysis* capabilities and procedure(s) to address analysis quality issues. When completed, the project will have addressed recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	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 a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.

Reliability Functions		
☐	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 service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	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.
☒	2. The frequency and voltage of interconnected bulk power 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 power 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 power systems shall be developed, coordinated, maintained and implemented.

Reliability and Market Interface Principles	
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power 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 of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability 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**
Project 2014-03 Revisions to TOP and IRO Standards	Proposed TOP and IRO standards and definitions from Project 2014-03 require RC, TOP, and BAs to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed standards and definitions are pending regulatory approval.

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

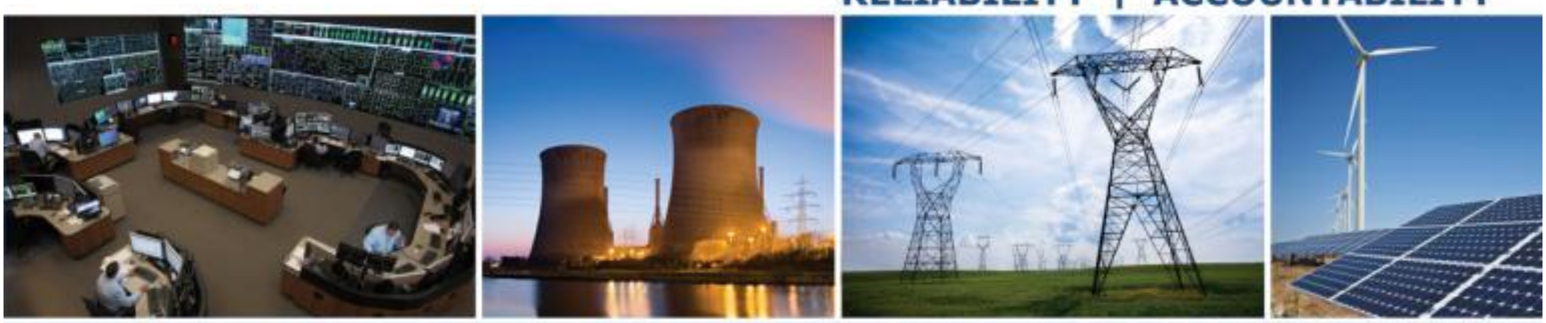
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Justification

Project 2009-02 Real-time Monitoring and Analysis Capabilities

RELIABILITY | ACCOUNTABILITY



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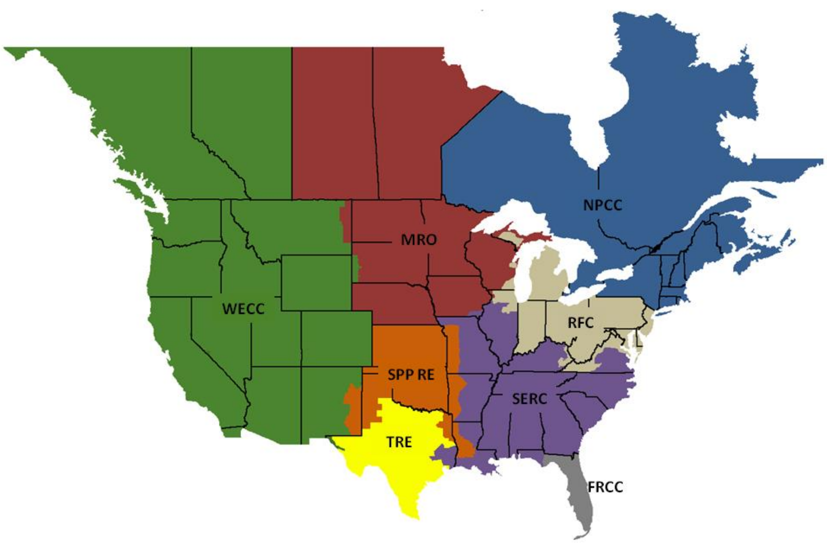
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

In April 2015, the Standards Committee appointed a new Standards Authorization Request (SAR) Drafting Team (SAR DT) for Project 2009-02 Real-time Monitoring and Analysis Capabilities. This project originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). Several new Reliability Standards and defined terms have been approved or filed for approval in the years since Project 2009-02 was initiated, including the standards developed in Project 2014-03 Revisions to TOP and IRO Standards. As a result, many of the original issues identified by the RTBPTF for Project 2009-02 have been addressed. In addition, relevant observations and recommendations have emerged from more recent events on the Bulk Electric System (BES) and operating practices have evolved over time. The SAR DT has reviewed previous work done in Project 2009-02, new standards and defined terms, relevant industry report findings and recommendations including those contained in the 2011 Southwest Outage report, and industry observations and practices relevant to real-time situational awareness to assist in developing a comprehensive SAR.

This white paper describes the SAR DT's approach to developing the SAR and discusses the technical basis for developing Reliability Standards in Project 2009-02. This white paper and the associated SAR together are intended to fully describe the project purpose, industry need, and project scope.

Chapter 1 – Background

FERC Order No. 693[1] highlights the need for a minimum set of capabilities to be available to assist operators in making real-time decisions. The work done by the RTBPTF, which was formed by NERC in response to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, became the basis for the Real-time Monitoring and Analysis Capabilities (RTMAC) standards development project when it was initiated in 2009. Although Reliability Standards affecting the operating reliability of the Bulk Electric System (BES) have improved significantly over the years since first becoming mandatory in 2007, a reliability issue has persisted in the area of real-time situational awareness capabilities as highlighted in BES event reports and an independent review of the NERC Reliability Standards. A review of industry reports and recommendations pertaining to real-time monitoring and analysis capabilities is provided in this document and in the Appendix. These recommendations, along with the FERC Order No. 693 directives, describe the industry need for the current RTMAC standards project.

BES Event Reports

Project 2009-02, like some other Reliability Standards projects, is informed by the lessons learned from past outages. The two significant outages discussed below highlight issues in real-time situational awareness, among other reliability concerns. Many Communications (COM), Transmission Operations (TOP), and Interconnection Reliability Operations (IRO) standards have addressed event report recommendations to improve the way the BES is planned and operated. The scope of Project 2009-02 is intended to include remaining recommendations from the 2003 Blackout Report and the 2011 Southwest Outage Report that pertain to real-time monitoring and analysis capabilities.

2003 Blackout Report

The largest blackout in history to affect North America began on the afternoon of August 14, 2003 and disrupted over 61,800 Megawatts of electric load in the Northeastern U.S. and the Canadian province of Ontario. Severe impacts to electrical service lasted for nearly one week and an estimated 50 million people were affected. A comprehensive investigation conducted by U.S. and Canadian government and industry leaders identified a host of principal and contributing causes, including:

- Failure to maintain adequate reactive power support,
- Failure to ensure operation within secure limits,
- Inadequate vegetation management,
- Inadequate operator training,
- Failure to identify emergency conditions and communicate that status to neighboring systems, and
- Inadequate regional-scale visibility over the Bulk-Power System (BPS).

Among other causes, the 2003 blackout was linked to dysfunction of SCADA/EMS systems. Additionally, investigators pointed out that several deficiencies leading to the 2003 blackout were also identified weaknesses in previous outages, indicating the need for more effective response. Previous post-event reports included recommendations aimed at improving capabilities for visualizing changes to facilities within the system, and for visualizing changes to facilities in neighboring systems that could have a potential impact. A recurring recommendation also focused on providing capabilities for operators to evaluate courses of action. These

[1] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, 72 Fed. Reg. 16416 at P 1660 (Apr. 4, 2007), FERC Stats. And Regs.¶ 31,242, *order on reh'g,* Order No. 693-A, 120 FERC ¶ 61,053 (2007) (Order No. 693).

observations led to the recommendation in the final report of the 2003 blackout for NERC to **evaluate and adopt better real-time tools for operators and reliability coordinators.**[2]

In response, the NERC Operating Committee organized the RTBPTF to study the real-time situational awareness practices in use within the electric power industry and make recommendations concerning the establishment of minimum capabilities necessary for reliable operations. The RTBPTF report *Real-time Tools Survey Analysis and Recommendations,*[3] completed in 2008, is the result of extensive information gathering and analysis and includes recommendations for new or enhanced Reliability Standards, operating guides, and areas for further analysis. This report became a basis for initiating the Real-time Monitoring and Analysis Capabilities project in 2009.

Although exhaustive and comprehensive, some of the RTBPTF recommendations go beyond the scope of situational awareness monitoring and capabilities. In addition, many other recommendations have been addressed in other subsequent standards projects. The appendix provides a description of RTBPTF report recommendations and the SAR DT's determination of applicability within the scope of Project 2009-02.

An early Concept White Paper describing potential performance, availability, quality, and maintenance parameters based on the RTBPTF Report was developed in 2011. The SAR DT reviewed the white paper and confirmed that, due to significant changes to Reliability Standards and operating practices since it was drafted, the 2011 Concept White Paper is no longer relevant to the current effort in Project 2009-02.

2011 Southwest Outage Report

Like the 2003 blackout in the northeast, the blackout that occurred in the southwest in September 2011 was partly due to, or exacerbated by, inadequate real-time situational awareness. On the afternoon of September 8, 2011, the loss of a single 500 kV line led to widespread cascading outages affecting 2.7 million customers in Arizona, Southern California, and Baja, Mexico. Inadequate operations planning was a significant factor in the failure to maintain a secure N-1 state. However, the report also highlighted several concerns with entities and their ability to monitor, identify, and plan for the next most critical contingency in real-time.[4]

Project 2014-03 - Revisions to TOP and IRO Standards addressed many of the recommendations contained in the 2011 Southwest Outage Report related to operations planning and real-time situational awareness. A complete description is provided in the Southwest Outage Report mapping document for Project 2014-03.[5] Revised definitions and performance requirements for Real-time Assessments and Operational Planning Analysis and proposed requirements for developing and implementing Operating Plans to prevent and mitigate operating limit exceedances address most of the real-time situational awareness recommendations from the report. However some recommendations contain aspects pertaining to real-time capabilities that should be considered in Project 2009-02, as described in the appendix. Accordingly, Project 2009-02 will develop requirements to address remaining recommendations as described in the following chapter.

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[2] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* Recommendation 22, available at http://www.nerc.com/pa/rrm/ea/2003%20Blackout%20Final%20Report/Forms/AllItems.aspx.

[3] *Real-Time Tools Survey Analysis and Recommendations* (March 13, 2008), available at http://www.nerc.com/comm/OC/Realtime%20Tools%20Best%20Practices%20Task%20Force%20RTBPTF%2020/Real-Time%20Tools%20Survey%20Analysis%20and%20Recommendations.pdf.

[4] *Arizona-Southern California Outages on September 8, 2011* (April 2012), available at http://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf.

[5] See the project page for 2014-03, available at http://www.nerc.com/pa/stand/pages/project-2014-03-revisions-to-top-and-iro-standards.aspx.

FERC Directives

In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to operators.[6] FERC indicated that the intent of the directive is to ensure operating entities have adequate tools to perform their real-time reliability functions.[7]

- P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.*
- P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.*
- P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.*

Independent Experts Review Project (IERP) Report

In 2013, NERC retained a team of five industry experts to assess the quality of the enforceable body of standards and make recommendations for improvements that could be implemented by NERC and the industry.[8] Among the recommendations made by the panel of experts was the identification of potential risks to reliability that may not be adequately addressed in Reliability Standards. The report recommended resuming development of the Real-time Monitoring and Analysis Capabilities standards project.

Proposed TOP and IRO Standards

Since Project 2009-02 was initiated in 2009, many standards and definitions have been revised or developed that address real-time situational awareness issues. In particular, the revised TOP and IRO standards in Project 2014-03, which are pending regulatory approval, include key provisions for real-time situational awareness and operations planning. In reviewing the RTBPTF report recommendations for applicability in the current Project 2009-02 effort, the SAR DT considered the Project 2014-03 standards as noted in the Appendix.

The proposed TOP and IRO standards in Project 2014-03 provide requirements for performing monitoring and analysis through the definition of Real-time Assessment, Operational Planning Analysis, and the relevant requirements. Accordingly, additional requirements to perform monitoring or analysis will not be included in the scope for Project 2009-02. Furthermore, requirements for data exchange to support real-time monitoring and analysis will not be included in scope for Project 2009-02 because they are addressed through data specification requirements in IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3.

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[6] Order No. 693 at P 905 (approving IRO-002-1 and directing modifications) and P 1665 (approving TOP-006-1 and directing modifications.

[7] Additionally, in approving VAR-001-1 - Voltage and Reactive Control, the Commission directed NERC to develop modifications to the standard to require periodic performance of voltage stability analysis to assist in real-time operations. The commission clarified that this could be accomplished through online tools where available, or offline simulation tools.

- §1875: *...[w]e direct the ERO, through its Reliability Standards development process, ...to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.*

VAR-001 was revised in the Project 2013-04, however the revised standard did not include a requirement for periodic performance of voltage stability analysis because voltage stability analysis is performed per SOL Methodology developed under FAC standards.

[8] See The Standards Independent Experts Review Project report. Available at www.nerc.com /pa/Stand/_layouts/xlviewer.aspx?id=/pa/Stand/Documents/P81_and%20IERP_Recommendations_for_Retirement_010815.xlsx.

Technical Conference

NERC and the SAR DT held a Technical Conference in Atlanta on June 4, 2015, to obtain industry input on reliability issues to be addressed in the proposed project. Participant subject matter experts representing a diverse mix of regional and functional entities shared their perspectives on the use of real-time situational awareness capabilities for reliable operations. There was consensus that many RTBPTF recommendations have been addressed in current or proposed TOP and IRO standards. However, Technical Conference participants agreed that issues identified by the RTBPTF pertaining to availability and information quality of real-time monitoring and analysis capabilities were still relevant.

Chapter 2 – Project Scope

The SAR DT has reviewed all recommendations from the RTBPTF and relevant recommendations from event reports, along with the existing body of standards, to identify remaining issues that should be in the scope for Project 2009-02. Table 1 below shows the resulting recommendations to be addressed. Additionally, the project will address outstanding FERC directives discussed in the preceding chapter.

Table 1: Report Recommendations to Address in Project 2009-02

Source	Recommendation	Discussion	Applicable Entity
2003 Blackout Report	Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators.	Project 2009-02 will develop requirements for real-time reliability monitoring and analysis capabilities to address issues not already addressed in other Reliability Standards. RTBPTF report recommendations will be considered in development.	RC, TOP, BA
2011 Southwest Outage Report	Recommendation 12 - [entities] should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2009-02 will develop requirements to improve the adequacy and operation of real-time monitoring and analysis capabilities. Requirements addressing the frequency that real-time tools run are contained in other standards and are not in the scope of this project.	RC, TOP, BA
RTBPTF Report	S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • Alarm Tools • Telemetry Data Systems • Network Topology Processor • State Estimator • Contingency Analysis	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. Prescription of specific tools is not in scope. Project approach is discussed below.	RC, TOP, BA as discussed below
RTBPTF Report	S7 - S8, S11-S12, S40 - Availability of various monitoring and analysis capability processes	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring capabilities are not available (i.e., not performing their intended function).	RC, TOP, BA

Project Purpose and Approach

Project 2009-02 will develop requirements for real-time monitoring and analysis capabilities used by operators in support of reliable System operations. Functional requirements for performing *monitoring* and *analysis* tasks are well established in Reliability Standards as discussed throughout this white paper. However, reliability could be improved by:

- Developing a common understanding of *monitoring* as it applies to real-time situational awareness of the BES,
- Providing operators with indication(s) of the quality of information being provided by *monitoring* and *analysis* capabilities, and
- Providing operators with notification(s) during unplanned loss of *monitoring* capabilities.

Project 2009-02 will develop requirements and definition(s), as needed, to accomplish these reliability objectives as discussed.

Real-time Situational Awareness Concept

From the RTBPTF Report:

> *Situational awareness, as RTBPTF understands it, means ensuring that accurate information on current system conditions, including the likely effects of future contingencies, is continuously available in a form that allows operators to quickly grasp and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations.*

The Project 2009-02 SAR DT believes that situational awareness encompasses two broad capabilities: monitoring and analysis. To be effective in supporting real-time situational awareness, monitoring and analysis must:

- Be performed with sufficient frequency to allow operators to understand operating conditions and take corrective actions when necessary,
- Provide awareness of information quality to allow operators to assess the accuracy of information being received on system conditions and take corrective actions when necessary, and
- Indicate when monitoring or analysis processes are not operating normally or are unavailable in order to provide operator awareness of the accuracy of the information being provided.

Project 2009-02 will develop new requirements and definition(s), as needed, that support this concept of situational awareness without duplicating aspects that are already addressed in the existing and proposed body of Reliability Standards. As discussed in the preceding chapter, requirements for the Reliability Coordinator (RC), Transmission Operator (TOP), and Balancing Authority (BA) to perform monitoring and analysis are covered under existing and proposed TOP and IRO standards. Therefore, Project 2009-02 will focus on developing requirements to address information quality and operator awareness of real-time monitoring and analysis capabilities. Table 2 shows reliability objectives that should be addressed in requirements for this project.

Monitoring

Monitoring BES facilities in real-time is a primary function of the RCs, TOPs, and BAs and is addressed in existing and proposed TOP and IRO standards. For RCs, proposed IRO-002-4 states:

> *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.*

For TOPs and BAs, proposed TOP-001-3 states:

> *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.*

The SAR DT understands *monitoring* capabilities may include both alarming and information visualization. Project 2009-02 will aim to develop a consistent understanding of *monitoring* within the industry. The project will also address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of information being provided by a monitoring system, and indication when a monitoring system is not operating normally.

Analysis

The *analysis* component of the Real-time situational awareness concept is described by the definition of Real-time Assessment, which is pending FERC approval along with the proposed TOP and IRO standards. The proposed definition is as follows:

> ***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.)*

Requirements for performing Real-time Assessments are contained in proposed IRO-008-2 and TOP-001-3:

> ***Proposed IRO-008-2***
> *R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.*
>
> ***Proposed TOP-001-3***
> *R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.*

The SAR DT believes the proposed definition of Real-time Assessment and the requirements in proposed IRO-008-2 and TOP-001-3 provide RCs and TOPs with flexibility to determine which real-time tools, such as State Estimator, Contingency Analysis, and Stability Applications, are necessary to meet their real-time reliability functions. Consequently, prescriptive requirements for real-time tools are not in scope for Project 2009-02.

The project will address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of the analysis used in Real-time Assessments.

Table 2: Project 2009-02 Reliability Objectives		
	Monitoring Capabilities	**Analysis Capabilities**
Quality	Provide operator with indication of information quality and procedures to address data quality issues.	Provide operator with indication of information quality and procedures to address analysis quality issues.
Availability	Provide operator with notification any time monitoring system is not operating normally.	N/A

Appendix – Report Recommendations

The table below contains recommendations for improved real-time situational awareness capabilities found in relevant industry reports and how these recommendations have been addressed, if applicable. If recommendations have not been addressed fully, the table includes a description of how they should be addressed in Project 2009-02. The following industry reports are considered here[9]:

- 2003 Blackout Final Report
- 2011 Southwest Outage Report
- Real-time Tools Best Practices Task Force

Report Recommendation Mapping	
Report Recommendation	**Applicable Standard(s)**
2003 Blackout Final Report	
Recommendation 1-21, 23-46	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators. Operating Committee to evaluate the real-time operating tools necessary for reliability operation and reliability coordination, including backup capabilities. The committee's report is to address both minimum acceptable capabilities for critical reliability functions and a guide to best practices.	The Operating Committee established the RTBPTF to evaluate real-time operating tools and make recommendations for proposed standards. Project 2009-02 should consider these recommendations as discussed below.
2011 Southwest Outage Report	
Recommendation 1-10, 13-26	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 11 - TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Project 2014-03 developed the proposed definition of Real-time Assessment and proposed TOP-003-3 Requirement R1 which describes the requirements for a data specification that will provide all of the data that a TOP needs in order to fulfill its reliability function. Together, these address capabilities and required data TOPs must have to ensure adequate situational awareness. **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.) **Proposed TOP-003-3, Requirement R1, Part 1.1**:

[9] *All industry reports are available on the 2009-02 Project Page: http://www.nerc.com/pa/Stand/Pages/Project-2009-02-Real-time-Reliability-Monitoring-and-Analysis-Capabilities.aspx.*

	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.
Recommendation 12 - TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2014-03 developed a requirement for the performance of a Real-time Assessment for Transmission Operators. Standards developed in Project 2009-02 will address the adequacy of tools as described in this recommendation. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
Recommendation 27 - TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences.	Proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA) developed in Project 2014-03 specify that identified phase angle limitations must be considered and deal with applying phase angle information. Proposed TOP-002 Requirement R2 specifies that TOPs must have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified in the OPA. Data specification requirements in approved IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3 provide a means for RCs and TOPs to obtain phase angle information. **Proposed Definition: 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.) **Proposed Definition: 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.) **Proposed TOP-002-4** 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.
RTBPTF Report	
S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • **Alarm Tools** • **Telemetry Data Systems** • **Network Topology Processor** • **State Estimator** • **Contingency Analysis**	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. However, prescription of specific tools is not in scope.
S2 - Compile and maintain a list of all bulk electric system elements within RC's area of responsibility.	Not in scope. Reliability objective is accomplished through monitoring and analysis requirements as discussed below.
S3 - Add new requirements and measures pertaining to RC monitoring of the bulk electric system.	Addressed in IRO standards (current and proposed). **IRO-002-2** R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. **IRO-003-2** R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. **Proposed IRO-002-4** 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.
S4 - Develop data-exchange standards.	Addressed in proposed TOP-001-3 and IRO-002-4. **Proposed TOP-001-3** R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area. R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it

	needs data from in order to maintain reliability in its Balancing Authority Area. **Proposed IRO-002-4** 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.
S5 - Develop data-availability standards and a process for trouble resolution and escalation.	Data availability and trouble resolution is addressed in IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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.
S6 - Develop a new weather data requirement related to situational awareness and real-time operational capabilities.	EOP-010-1 covers space weather dissemination. The SAR DT views monitoring other weather information as common utility practice that does not require a reliability standard.
S7 - Specify and measure minimum availability for alarm tools.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the

	RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function). Availability notification for analysis tools is addressed in IRO-008-1, and proposed IRO-008-2 proposed TOP-001-3 from Project 2014-30. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed IRO-008-2** R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
S8 - Specify and measure minimum availability for network topology processor.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S9 - Establish a uniform formal process to determine the “wide area view boundary” and show boundary data/results.	Wide-area is now a defined term. Recommendation has been addressed.
S10 - Develop compliance measures for verification of the usage of “wide-area overview display” visualization tools.	IRO standards revisions have addressed compliance measures.
S11 - Specify and measure minimum availability for state estimator, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S12 - Specify and measure minimum availability for contingency analysis, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S13 - Specify criteria and develop measures for defining contingencies.	Not in scope; Addressed in approved TPL and FAC standards.
S14 - Perform one-hour-ahead power-flow simulations to assess approaching SOL and IROL violations and corresponding measures.	Requirements for assessing pre- and post-contingency system conditions are addressed in Real-time Assessment (RTA) and Operational Planning Analysis (OPA) definitions. Requirements for performing RTA and OPA are contained in

	proposed TOP-001-3, TOP-002-4, IRO-008-2, and approved IRO-008-1. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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. R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed definition** **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.) **Proposed definition** **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.)
S15 - Provide real-time awareness of load-shed capability to address potential or actual IROL violations.	Addressed in proposed EOP-011-1, approved IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

	2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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.
S16 - Require BAs to monitor contingency reserves and calculate contingency reserves at a minimum periodicity of 10 seconds.	BA responsibilities for managing Contingency Reserve are addressed in the approved BAL-002-1 standard which is under revision in Project 2010-014. 1. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.
S17 - Revise the current-day operations requirements to delineate specific, independent requirements for monitoring operating and reactive reserves.	Addressed in VAR-001-4, BAL-002, and proposed IRO-002-4 and TOP-001-3. **VAR-001-4** R4. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. **Proposed IRO-002-4** **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. **Proposed TOP-001-3** 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.
S18 - Establish document plans and procedures for conservative operations.	Addressed in proposed EOP-011-1 Requirement R1. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating

	Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

S19 - Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes.	Addressed in proposed TOP-001-3, and IRO-008-2 and the proposed definitions for Operational Planning Analysis and Real-time Assessment. **Proposed TOP-001-3** R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. 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 an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-008-2** 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. **Proposed definition** **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.) **Proposed definition** **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.)
S20 - Develop formal operating guides (mitigation plans) and measures for each IROL and any SOL or other conditions having a potential impact on reliability.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S21 - Review and update operating guides (mitigation plans) when day-ahead or current day studies indicate the potential need to implement an operating guide.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S22 - Provide temporary operating guides (mitigation plans) with control actions for situations that could affect reliability but that have not been identified previously.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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.
S23 - Develop joint operating guides (mitigation plans) for situations that could require more than one RC or more than one TOP to execute actions.	Addressed in IRO-014-2, proposed IRO-014-3 and proposed IRO-008-2. **IRO-014-2** R1. Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall collectively address the following: ... **Proposed IRO-014-3** 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: ... **Proposed IRO-008-2** 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.
S24 - Develop a formal procedure to document the processes for developing, reviewing, and updating operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S25 - Incorporate verifiable and traceable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates when modifying operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S26 - Write operating guides (mitigation plans) in clear, unambiguous language, leaving nothing to interpretation.	Not in scope. This is administrative in nature.
S27 - State the specific purpose of existence for each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S28 - Summarize the specific situation assessment and address the method of performing the assessment in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S29 - Identify all appropriate preventive and remedial control actions in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S30 - Develop criteria in operating guides (mitigation plans) to support decisions regarding whether a specific control action should be taken.	Not in scope. This is administrative in nature.
S31 - Incorporate on-line tools that utilize on-line data when operating guides (mitigation plans) require calculations.	Not in scope. Recommendation is appropriate as a guideline rather than a reliability standard.
S32 - Make operating guides (mitigation plans) readily available via a quick-access method such as Web-based help, EMS display notes, or on-line help systems.	Not in scope. This is administrative in nature.
S33 - Provide the location, real-time status, and MWs of load available to be shed.	Addressed in proposed EOP-011-1 Requirement R1 Part 1.2.5 and proposed TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

	1.2.6. Reliability impacts of extreme weather conditions. **Proposed TOP-003-3** 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. ...
S34 - Establish documented procedures for the reassessment and re-posturing of the system following an event.	Addressed in proposed TOP-002-4 and IRO-008-2, and approved EOP-005-2 and EOP-006-2. **Proposed TOP-002-4** 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. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** 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. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ...

	EOP-006-2 R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S35 - Provide information to operators to maintain awareness of the availability and capability of the blackstart generators and transmission restoration paths.	Addressed in approved IRO-010-1, proposed TOP-003-3, proposed IRO-010-2, approved EOP-005-2, and approved EOP-006-2. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... R1.6. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. ... **Proposed TOP-003-3** 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. ... **Proposed IRO-010-2** 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. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ... R1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit. ... R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **EOP-006-2** R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S36 - Plan and coordinate scheduled outages of blackstart generators and transmission restoration paths.	Addressed in approved EOP-005-2 and proposed IRO-017-1 - Outage Coordination. **EOP-005-2** R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **Proposed IRO-017-1** R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation

	and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: ...
S37 - Maintain a Critical Equipment Monitoring Document to identify tools and procedures for monitoring critical equipment.	Not in scope. This is administrative in nature.
S38 - Maintain event logs pertaining to critical equipment status for a period of one year.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be "installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools". Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S39 - Maintain a Critical Equipment Maintenance and Testing Document identifying tools and procedures for maintenance, modification, and testing of critical equipment.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be "installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools". Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S40 - Monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation.	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and analysis capabilities are not available (i.e., not performing their intended function).

Violation Risk Factor and Violation Severity Level Justifications

Project 2009-02 Real-time Monitoring and Analysis Capabilities

This document provides the Standard Drafting Team's (SDT) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in Project 2009-02.

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 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.

FERC Violation Risk Factor Guidelines

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

The Commission seeks to ensure that VRFs 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 VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of VRFs 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 VRF 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

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

FERC's 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 Justification

The requirements in IRO-018-1 and TOP-010-1 were developed to address certain issues related to the Real-time monitoring and analysis capabilities used by operators of the BES. IRO-018-1 contains five requirements applicable to Reliability Coordinators (RCs), while TOP-010-1 contains seven analogous requirements for Transmission Operators (TOPs) and Balancing Authorities (BAs). A Medium VRF is proposed for all requirements in both standards according to the guidelines as explained below.

VRF Justifications – IRO-018-1 (R1-R3) and TOP-010-1 (R1-R4)	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A. The requirements are not directly connected to conclusions from the 2003 Blackout, but rather address specific recommendations from NERC Technical Committees.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard. The requirements have no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. These are new requirements. The VRFs in IRO-018-1 are consistent with those contained in TOP-010-1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A VRF of Medium is consistent with the NERC VRF definition. The requirements in IRO-018-1 and TOP-010-1 address issues related to the quality and availability of monitoring and analysis capabilities used by RCs, TOPs, and BAs in maintaining reliable operations. Violation of any of these requirements could directly affect the ability to effectively monitor and control the Bulk Electric System. However, violation of any of these requirements is unlikely to lead to Bulk Electric System instability, separation, or cascading failures. Therefore, a VRF of Medium is appropriate.

VRF Justifications – IRO-018-1 (R1-R3) and TOP-010-1 (R1-R4)	
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. Each requirement contains one objective, therefore a single VRF is assigned to each requirement.

VSL Justification

Proposed VSLs – IRO-018-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to

			perform its Real-time monitoring and Real-time Assessments.

VSL Justifications – IRO-018-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – IRO-018-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 2.1 through Part 2.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any

	of the elements listed in Part 2.1 through Part 2.3.		of the elements listed in Part 2.1 through Part 2.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.

VSL Justifications – IRO-018-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to 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 proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – IRO-018-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator has an alarm process monitor but	The Reliability Coordinator does not have an alarm process

		the alarm process monitor did not provide a notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

VSL Justifications – IRO-018-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time

	monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.

VSL Justifications – TOP-010-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 through Part 2.3.	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include two of the elements listed in Part 2.1 through Part 2.3.	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.

VSL Justifications – TOP-010-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.

FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4	The proposed VSL is not based on a cumulative number of violations.

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

Proposed VSLs – TOP-010-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 through Part 3.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.

VSL Justifications – TOP-010-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL is worded consistently with the corresponding requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity has an alarm process monitor but the alarm process monitor did not provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The responsible entity does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

VSL Justifications – TOP-010-1, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.

FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4	The proposed VSL is not based on a cumulative number of violations.

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

Violation Risk Factor and Violation Severity Level Justifications

Project 2009-02 Real-time Monitoring and Analysis Capabilities

This document provides the Standard Drafting Team's (SDT) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in Project 2009-02.

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 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.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that VRFs 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 VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of VRFs 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 VRF 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

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

FERC's 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 Justification

The requirements in IRO-018-1 and TOP-010-1 were developed to address certain issues related to the Real-time monitoring and analysis capabilities used by operators of the BES. IRO-018-1 contains five requirements applicable to Reliability Coordinators (RCs), while TOP-010-1 contains seven analogous requirements for Transmission Operators (TOPs) and Balancing Authorities (BAs). A Medium VRF is proposed for all requirements in both standards according to the guidelines as explained below.

VRF Justifications – IRO-018-1 (R1-~~R5~~R3) and TOP-010-1 (R1-~~R7~~R4)	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A. The requirements are not directly connected to conclusions from the 2003 Blackout, but rather address specific recommendations from NERC Technical Committees.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard. The requirements have no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. These are new requirements. The VRFs in IRO-018-1 are consistent with those contained in TOP-010-1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A VRF of Medium is consistent with the NERC VRF definition. The requirements in IRO-018-1 and TOP-010-1 address issues related to the quality and availability of monitoring and analysis capabilities used by RCs, TOPs, and BAs in maintaining reliable operations. Violation of any of these requirements could directly affect the ability to effectively monitor and control the Bulk Electric System. However, violation of any of these requirements is unlikely to lead to Bulk Electric System instability, separation, or cascading failures. Therefore, a VRF of Medium is appropriate.

VRF Justifications – IRO-018-1 (R1-~~R5~~R3) and TOP-010-1 (R1-~~R7~~R4)	
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. Each requirement contains one objective, therefore a single VRF is assigned to each requirement.

VSL Justification

Proposed VSLs – IRO-018-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.~~N/A~~	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3. ~~The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one~~	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to

		~~of the elements listed in Part 1.1 and Part 1.2.~~	perform its Real-time monitoring and Real-time Assessments.~~The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 and Part 1.2;~~ ~~OR~~ ~~The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.~~

VSL Justifications – IRO-018-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. ~~Two~~ Three VSLs are specified for a graduated scale.
FERC VSL G1	There is no prior compliance obligation related to the subject of this standard.

Violation Severity Level Assignments Should Not Have the Unintended 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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4	The proposed VSL is not based on a cumulative number of violations.

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

~~Proposed VSLs—IRO-018-1, R2~~			
~~Lower~~	~~Moderate~~	~~High~~	~~Severe~~
~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its Real-time monitoring and Real-time Assessments.~~

~~VSL Justifications—IRO-018-1, R2~~	
~~NERC VSL Guidelines~~	~~Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.~~
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of~~	~~There is no prior compliance obligation related to the subject of this standard.~~

~~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~~	~~The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.~~ ~~Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.~~ ~~Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.~~
~~FERC VSL G4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A~~	~~The proposed VSL is not based on a cumulative number of violations.~~

~~Cumulative Number of Violations~~	

Proposed VSLs – IRO-018-1, ~~R3~~R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 2.1 through Part 2.3.~~N/A~~	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 2.1 through Part 2.3.~~The Reliability Coordinator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 and Part 3.2.~~	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.~~The Reliability Coordinator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include any~~

			~~of the elements listed in Part 3.1 and Part 3.2.;~~ ~~OR~~ ~~The Reliability Coordinator did not implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments.~~

VSL Justifications – IRO-018-1, ~~R3~~R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. ~~Two~~ Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to 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 proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

~~Proposed VSLs — IRO-018-1, R4~~			
~~Lower~~	**~~Moderate~~**	**~~High~~**	**~~Severe~~**
~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.~~

~~VSL Justifications — IRO-018-1, R4~~	
~~NERC VSL Guidelines~~	~~Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.~~
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~There is no prior compliance obligation related to the subject of this standard.~~
~~FERC VSL G2~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~	~~The proposed VSL is written to 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 proposed VSL is binary and assigned a Severe VSL.~~ ~~Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.~~
~~FERC VSL G4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~The proposed VSL is not based on a cumulative number of violations.~~

Proposed VSLs – IRO-018-1, ~~R5~~R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator has an alarm process monitor but	The Reliability Coordinator does not have an alarm process

		the alarm process monitor did not provide a notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.~~N/A~~	monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ~~The Reliability Coordinator did not utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.~~

VSL Justifications – IRO-018-1, ~~R5~~R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.~~The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.~~
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R1

Lower	Moderate	High	Severe
N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.~~N/A~~	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3. ~~The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 and Part 1.2.~~	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.~~The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any~~

			~~of the elements listed in Part 1.1 and Part 1.2;~~ ~~OR~~ ~~The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.~~

VSL Justifications – TOP-010-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. ~~Two~~ Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Proposed VSLs – TOP-010-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 through Part 2.3.~~N/A~~	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include two of the elements listed in Part 2.1 through Part 2.3. ~~The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 and Part 2.2.~~	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.~~The Balancing Authority's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any~~

			~~of the elements listed in Part 2.1 and Part 2.2.;~~ ~~OR~~ ~~The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.~~

VSL Justifications – TOP-010-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. ~~Two~~ Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to 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 proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

~~Proposed VSLs — TOP-010-1, R3~~			
~~Lower~~	~~Moderate~~	~~High~~	~~Severe~~
~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not provide its System~~

			~~Operators with indication(s) of the quality of Real-time data used to perform its Real-time monitoring and Real-time Assessments.~~

~~VSL Justifications — TOP-010-1, R3~~	
~~NERC VSL Guidelines~~	~~Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.~~
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~There is no prior compliance obligation related to the subject of this standard.~~
~~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~~	~~The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.~~ ~~Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.~~

~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.~~
~~FERC VSL G4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~The proposed VSL is not based on a cumulative number of violations.~~

~~Proposed VSLs — TOP-010-1, R4~~			
~~Lower~~	~~Moderate~~	~~High~~	~~Severe~~
~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its analysis functions and Real-time monitoring.~~

~~VSL Justifications — TOP-010-1, R4~~	
~~NERC VSL Guidelines~~	~~Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.~~
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~There is no prior compliance obligation related to the subject of this standard.~~
~~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~~	~~The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.~~ ~~Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.~~ ~~Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.~~
~~FERC VSL G3~~	~~The proposed VSL is worded consistently with the corresponding requirement.~~

~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	
~~FERC VSL G4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~The proposed VSL is not based on a cumulative number of violations.~~

Proposed VSLs – TOP-010-1, ~~R5~~R3			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 through Part 3.3.~~N/A~~	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 3.1 through Part 3.3.~~The Transmission Operator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not~~	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 through Part 3.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure

		~~include one of the elements listed in Part 5.1 and Part 5.2.~~	to address the quality of analysis used in its Real-time Assessments.~~The Transmission Operator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include any of the elements listed in Part 5.1 and Part 5.2.;~~ ~~OR~~ ~~The Transmission Operator did not implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments.~~

VSL Justifications – TOP-010-1, ~~R5~~R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. ~~Two~~ Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of	There is no prior compliance obligation related to the subject of this standard.

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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A	The proposed VSL is not based on a cumulative number of violations.

Cumulative Number of Violations	

~~Proposed VSLs — TOP-010-1, R6~~			
~~**Lower**~~	~~**Moderate**~~	~~**High**~~	~~**Severe**~~
~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.~~

~~VSL Justifications — TOP-010-1, R6~~	
~~NERC VSL Guidelines~~	~~Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.~~
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~There is no prior compliance obligation related to the subject of this standard.~~
~~FERC VSL G2~~ ~~Violation Severity Level Assignments Should Ensure~~	~~The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.~~

~~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 proposed VSL is binary and assigned a Severe VSL.~~ ~~Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.~~
~~FERC VSL G4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~The proposed VSL is not based on a cumulative number of violations.~~

Proposed VSLs – TOP-010-1, ~~R7~~R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity has an alarm process monitor but the alarm process monitor did not provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.~~N/A~~	The responsible entity does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ~~The responsible entity did not utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.~~

VSL Justifications – TOP-010-1, ~~R7~~R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.~~The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.~~
FERC VSL G1	There is no prior compliance obligation related to the subject of this standard.

Violation Severity Level Assignments Should Not Have the Unintended 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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, 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 is worded consistently with the corresponding requirement.
FERC VSL G4	The proposed VSL is not based on a cumulative number of violations.

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

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P 905-906	Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.	Proposed IRO-018-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the Reliability Coordinator's (RC) monitoring and analysis capabilities. The monitoring and analysis capabilities required by proposed IRO-018-1 and other IRO standards discussed below ensure RCs have the capabilities to maintain Real-time situational awareness. **Monitoring Capabilities** Requirement R1 addresses the quality of the Real-time data needed by the RC to perform its monitoring and Real-time Assessments. Each RC is required to implement a documented procedure for addressing Real-time data quality issues. The procedure must include criteria for evaluating Real-time data quality, provisions for indicating data quality to the System Operator, and actions to resolve Real-time data quality issues when data quality affects Real-time Assessments. Requirement R3 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring RCs to use an alarm process monitor. Requirements for the RC to perform Real-time monitoring are specified in IRO-002-2, IRO-002-4, and IRO-003-2. ***Proposed IRO-018-1*** **R1.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time

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		monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating the quality of Real-time data; **1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and **1.3.** Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. **R3.** Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***IRO-002-2*** **R5.** Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. ***IRO-003-2*** **R1.** Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or

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		unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. ***IRO-002-4*** **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. **<u>Analysis Capabilities</u>** Requirement R2 addresses the quality of the analysis used by the RC to perform its Real-time Assessments. Each RC is required to implement a documented procedure to address the quality of the analysis used in its Real-time Assessments. The procedure must include criteria for evaluating the quality of analysis used in Real-time Assessments, provisions for indicating the quality of analysis, and actions to resolve analysis quality issues affecting its Real-time Assessments.. Requirements for the RC to perform Real-time Assessments are specified in IRO-008-1 and IRO-008-2. ***Proposed IRO-018-1*** **R2.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include:

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		2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments; **2.2** Provisions to indicate the quality of analysis used in its Real-time Assessments; and **2.3.** Actions to resolve analysis quality issues affecting its Real-time Assessments. ***IRO-008-1*** **R2.** Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. ***Definition of 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.) ***IRO-008-2*** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

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P 1660	We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.	Proposed TOP-010-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the monitoring and analysis capabilities used by Transmission Operators (TOPs) and Balancing Authorities (BAs). The monitoring and analysis capabilities required by TOP-010-1 and other TOP standards discussed below ensure TOPs and BAs have the capabilities to maintain Real-time situational awareness. **<u>Monitoring Capabilities</u>** Requirements R1 and R2 address the quality of the Real-time data needed by TOPs and BAs to perform their Real-time monitoring and Real-time analysis. Each TOP and BA is required to implement a documented procedure for addressing Real-time data quality issues. The procedure must include criteria for evaluating Real-time data quality, provisions for indicating data quality to the System Operator, and actions to resolve Real-time data quality issues when data quality affects analysis. Requirement R4 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring TOPs and BAs to use an alarm process monitor. Requirements for TOPs to perform Real-time monitoring are specified in TOP-001-3 and TOP-006-2. Requirements for BAs to perform Real-time monitoring are specified in TOP-006-2, TOP-001-3k and BAL standards. ***Proposed TOP-010-1*** **R1.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time

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		monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating the quality of Real-time data; **1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and **1.3.** Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. **R2.** Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: **2.1** Criteria for evaluating the quality of Real-time data; **2.2** Provisions to indicate the quality of Real-time data to the System Operator; and **2.3** Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data. **R4.** Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***TOP-006-2*** **R1.** Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

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		1.1. - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2.** - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. ***TOP-001-3*** **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. **<u>Analysis Capabilities</u>** Requirement R3 addresses the quality of the analysis used by the TOP to perform its Real-time Assessments. Each TOP is required to implement a documented procedure to address the quality of the analysis used in its Real-time Assessments. The procedure must include criteria for evaluating the quality of

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		analysis used in Real-time Assessments, provisions for indicating the quality of analysis, and actions to resolve analysis quality issues affecting its Real-time Assessments. Requirements for the TOP to perform Real-time Assessments are specified in TOP-003-3. ***Proposed TOP-010-1*** **R3.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: **3.1.** Criteria for evaluating the quality of any analysis used in its Real-time Assessments; **3.2.** Provisions to indicate the quality of analysis used in its Real-time Assessments; and **3.3.** Actions to resolve analysis quality issues affecting its Real-time Assessments. ***Definition of 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.) ***TOP-001-3*** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

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P 1875	...[w]e direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1 to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.	The directive was considered in developing the scope of Project 2009-02. NERC believes TOP, IRO, and VAR standards address the directive as discussed below. Accordingly, additional requirements were not developed in Project 2009-02. RCs and TOPs are required to periodically perform Real-time Assessments consisting of an evaluation of system conditions "to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions." Entities must use whatever analysis is necessary to obtain an evaluation of system conditions, which may include real-time voltage stability analysis. Real-time Assessments assist operators in maintaining operations within established SOLs and IROLs, to include voltage stability criteria. Requirements for performing Real-time Assessments are contained in IRO-008-1, IRO-008-2, and TOP-001-3 Reliability Standards as discussed above. VAR-001-1 was revised in Project 2013-04. The resulting standard, VAR-001-4, did not include an explicit requirement for periodic performance of voltage stability analysis because "such analysis would be performed pursuant to the SOL methodology developed under FAC standards."[1] VAR-001-4 requirement R1 specifies the TOP must establish a system voltage schedule as part of its plan to operate within SOLs and IROLs. ***VAR-001-4*** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate

1 Reliability Standard VAR-001-4.1, Guidelines and Technical Basis section, page 13. Available at: http://www.nerc.com/pa/Stand/Reliability%20Standards/VAR-001-4.1.pdf

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		within System Operating Limits and Interconnection Reliability Operating Limits. **1.1.** Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

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P 905-906	Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.	Proposed IRO-018-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the Reliability Coordinator's (RC) monitoring and analysis capabilities. The monitoring and analysis capabilities required by proposed IRO-018-1 and other IRO standards discussed below ensure RCs have the capabilities to maintain Real-time situational awareness. **Monitoring Capabilities** Requirement~~s~~ R1 ~~and R2~~ address<ins>es</ins> the quality of the Real-time data needed by the RC to perform its monitoring and Real-time Assessments. Each RC is required to implement a documented procedure for addressing Real-time data quality issues<ins>. The procedure must include criteria for evaluating Real-time data quality, provisions for indicating data quality to the System Operator, and actions to resolve Real-time data quality issues when data quality affects Real-time Assessments.</ins> ~~, including invalid or time-late data, and must provide System Operators with information to indicate the quality of data received.~~ Requirement ~~R5~~ <ins>R3</ins> addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring RCs to use an ~~independent~~ alarm process monitor. Requirements for the RC to perform Real-time monitoring are specified in ~~currently-enforceable~~ IRO-002-2, <ins>IRO-002-4, and</ins> IRO-003-2~~, and proposed IRO-002-4 from Project 2014-03~~. ***Proposed IRO-018-1***

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		R1. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating ~~potential Real-time data~~the quality of Real-time data;~~discrepancies including, but not limited to:~~ ~~**1.1.1.** Data outside of a prescribed data range;~~ ~~**1.1.2.** Analog data not updated within a predetermined time period;~~ ~~**1.1.3.** Data entered manually to override telemetered information; and~~ 1.1.1. ~~Data otherwise identified as invalid or suspect.~~ ~~1.1.4.~~1.2. Provisions to indicate the quality of Real-time data to the System Operator; and ~~1.2.~~1.3. Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.~~Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data.~~ ~~**R2.** Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.~~ ~~R5~~R3. Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.~~Each Reliability Coordinator shall~~

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		~~utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.~~ ***~~Currently-enforceable~~ IRO-002-2*** **R5.** Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. ***~~Currently-enforceable~~ IRO-003-2*** **R1.** Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. ***~~Proposed~~ IRO-002-4 ~~(pending regulatory approval)~~*** **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

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		Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Analysis Capabilities** Requirement~~s~~ ~~R3~~ R2 ~~and R4~~ address<u>es</u> the quality of the analysis used by the RC to perform its Real-time Assessments. Each RC is required to implement a documented procedure to ~~maintain~~ <u>address</u> the quality of the analysis used in its Real-time Assessments<u>. The procedure must include criteria for evaluating the quality of analysis used in Real-time Assessments, provisions for indicating the quality of analysis, and actions to resolve analysis quality issues affecting its Real-time Assessments.</u>~~and must provide System Operators with information to indicate the quality of this analysis~~. Requirements for the RC to perform Real-time Assessments are specified in ~~currently-enforceable~~ IRO-008-1 and ~~proposed~~ IRO-008-2. ***Proposed IRO-018-1*** ~~**R3**~~<u>**R2**</u>**.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to ~~maintain~~ <u>address</u> the quality of ~~any~~ analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: ~~**3**~~<u>**2**</u>**.1.** Criteria for evaluating the quality of ~~any~~ analysis used in its Real-time Assessments; <u>**2.2** Provisions to indicate the quality of analysis used in its Real-time Assessments; and</u> ~~and~~

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		~~3~~2.~~2~~3. Actions to resolve analysis quality ~~deficiencies in any analysis used in~~issues affecting its Real-time Assessments. ~~**R4.** Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.~~ ***~~Currently-enforceable~~ IRO-008-1*** **R2.** Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. ***~~Revised d~~Definition of Real-time Assessment ~~(pending regulatory approval)~~*** 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.) ***~~Proposed~~ IRO-008-2 ~~(pending regulatory approval)~~*** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
P 1660	We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a	Proposed TOP-010-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task

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	minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.	Force (RTBPTF) related to the availability and quality of the monitoring and analysis capabilities used by Transmission Operators (TOPs) and Balancing Authorities (BAs). The monitoring and analysis capabilities required by ~~proposed~~ TOP-010-1 and other TOP standards discussed below ensure TOPs and BAs have the capabilities to maintain Real-time situational awareness. **Monitoring Capabilities** Requirements R1 ~~through~~ and R~~4~~2 address the quality of the Real-time data needed by TOPs and BAs to perform their Real-time monitoring and Real-time analysis. ~~Each TOP and BA is required to implement a documented procedure for addressing Real-time data quality issues, including invalid or time-late data, and must provide System Operators with information to indicate the quality of data received.~~ Each TOP and BA is required to implement a documented procedure for addressing Real-time data quality issues. The procedure must include criteria for evaluating Real-time data quality, provisions for indicating data quality to the System Operator, and actions to resolve Real-time data quality issues when data quality affects analysis. Requirement ~~R7~~ R4 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring TOPs and BAs to use an ~~independent~~ alarm process monitor. Requirements for TOPs to perform Real-time monitoring are specified in ~~currently-enforceable~~ TOP-001-3 and TOP-006-2 ~~and proposed TOP-001-3 from Project 2014-03~~.

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		Requirements for BAs to perform Real-time monitoring are specified in ~~currently-enforceable~~ TOP-006-2, ~~proposed~~ TOP-001-3k ~~from Project 2014-03,~~ and BAL standards. ***Proposed TOP-010-1*** **R1.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating ~~potential~~ the quality of Real-time data; ~~quality discrepancies including, but not limited to:~~ ~~**1.1.1.** Data outside of a prescribed data range;~~ ~~**1.1.2.** Analog data not updated within a predetermined time period;~~ ~~**1.1.3.** Data entered manually to override telemetered information; and~~ ~~1.1.4.~~1.1.1. ~~Data otherwise identified as invalid or suspect.~~ **1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and ~~1.2.~~1.3. Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.~~Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data.~~ **R2.** Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis

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		functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: **2.1** Criteria for evaluating the quality of ~~potential~~ Real-time data ~~quality discrepancies including, but not limited to:~~; ~~**2.1.1.** Data outside of a prescribed data range;~~ ~~**2.1.2.** Analog data not updated within a predetermined time period;~~ ~~**2.1.3.** Data entered manually to override telemetered information; and~~ ~~**2.1.4.** Data otherwise identified as invalid or suspect.~~ **2.2** Provisions to indicate the quality of Real-time data to the System Operator; and **2.3** Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data. ~~**R3.** Each Transmission Operator shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.~~ ~~**R4.** Each Balancing Authority shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.~~ ~~**R7**~~**R4.** Each Transmission Operator and Balancing Authority shall have ~~utilize~~ an ~~independent~~ alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ~~***Currently-enforceable***~~ ***TOP-006-2***

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		R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. **1.1.** - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2.** - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. ***~~Proposed~~ TOP-001-3 ~~(pending regulatory approval)~~*** **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. **Analysis Capabilities** Requirement~~s~~ R~~5~~3 ~~and R6~~ address~~es~~ the quality of the analysis used by the TOP to perform its Real-time Assessments. Each

Order No. 693 Citation	Directive/Guidance	Resolution
		TOP is required to implement a documented procedure to ~~maintain~~ address the quality of the analysis used in its Real-time Assessments. ~~and must provide System Operators with information to indicate the quality of this analysis.~~ The procedure must include criteria for evaluating the quality of analysis used in Real-time Assessments, provisions for indicating the quality of analysis, and actions to resolve analysis quality issues affecting its Real-time Assessments. Requirements for the TOP to perform Real-time Assessments are specified in ~~proposed~~ TOP-003-3 ~~from Project 2014-03~~. ***Proposed TOP-010-1*** **~~R5~~R3.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to ~~maintain~~ address the quality of ~~any~~ analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: **~~5~~3.1.** Criteria for evaluating the quality of any analysis used in its Real-time Assessments; **3.2.** Provisions to indicate the quality of analysis used in its Real-time Assessments; and **~~5~~3.~~2~~3.** Actions to resolve analysis quality issues affecting ~~deficiencies in any analysis used in~~ its Real-time Assessments. ~~**R6.** Each Transmission Operator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.~~

Order No. 693 Citation	Directive/Guidance	Resolution
		~~Proposed d~~Definition of Real-time Assessment ~~(pending regulatory approval)~~ 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.) ***~~Proposed~~ TOP-001-3 ~~(pending regulatory approval)~~*** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
P 1875	...[w]e direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1 to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.	The directive was considered in developing the scope of Project 2009-02. NERC believes ~~currently enforceable IRO standards, proposed~~ TOP, ~~and~~ IRO, and VAR standards~~, and currently-enforceable VAR standards~~ address the directive as discussed below. Accordingly, additional requirements were not developed in Project 2009-02. RCs and TOPs are required to periodically perform Real-time Assessments consisting of an evaluation of system conditions "to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions." Entities must use whatever analysis is necessary to obtain an evaluation of system conditions, which may include real-time voltage stability analysis. Real-time Assessments assist operators in maintaining operations within established SOLs and IROLs, to include voltage stability criteria. Requirements for performing Real-time Assessments are contained in ~~currently-enforceable~~

Order No. 693 Citation	Directive/Guidance	Resolution
		IRO-008-1, ~~and proposed~~ IRO-008-2, and TOP-001-3 Reliability Standards as discussed above. VAR-001-1 was revised in Project 2013-04. The resulting standard, VAR-001-4, did not include an explicit requirement for periodic performance of voltage stability analysis because "such analysis would be performed pursuant to the SOL methodology developed under FAC standards."[1] VAR-001-4 requirement R1 specifies the TOP must establish a system voltage schedule as part of its plan to operate within SOLs and IROLs. ***~~Currently-enforceable~~ VAR-001-4*** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. **1.1.** Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

[1] Reliability Standard VAR-001-4.1, Guidelines and Technical Basis section, page 13. Available at: http://www.nerc.com/pa/Stand/Reliability%20Standards/VAR-001-4.1.pdf

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Standards Announcement

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities IRO-018-1 and TOP-010-1

Formal Comment Period Open through January 25, 2016

Now Available

A 45-day formal comment period for **IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities** and **TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities** is open through **8 p.m. Eastern, Monday, January 25, 2016**.

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 standards. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

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

Additional ballot for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **January 15-25, 2016**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

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Standards Announcement

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities IRO-018-1 and TOP-010-1

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Standards Announcement

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities IRO-018-1 and TOP-010-1

Additional Ballot and Non-binding Poll Results

Now Available

Additional ballots for **Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels concluded **8 p.m. Eastern, January 26, 2016.**

The standards are as follows:

- IRO-018-1 - **Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities**
- TOP-010-1 - **Real-time Reliability Monitoring and Analysis Capabilities**

The standards received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides the detailed results.

	Ballot	Non-binding Poll
Standard	Quorum / Approval	Quorum / Supportive Opinions
IRO-018-1	82.88 % / 72.13%	81.95% / 81.76%
TOP-010-1	82.18% / 68.01%	81.02% / 76.27%

Next Steps
The drafting team will consider all comments received during the formal comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/43)
Ballot Name: 2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 AB 2 ST
Voting Start Date: 1/15/2016 12:01:00 AM
Voting End Date: 1/26/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 242
Total Ballot Pool: 292
Quorum: 82.88
Weighted Segment Value: 72.14

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	73	1	36	0.783	10	0.217	0	14	13
Segment: 2	10	0.9	2	0.2	7	0.7	0	1	0
Segment: 3	68	1	30	0.789	8	0.211	0	15	15
Segment: 4	21	1	13	0.813	3	0.188	0	2	3
Segment: 5	63	1	26	0.743	9	0.257	0	18	10
Segment: 6	47	1	21	0.778	6	0.222	0	12	8
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	1	0.1	1	0.1	0	0	0
Segment:	2	0.1	1	0.1	0	0	0	0	1

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9									
Segment: 10	6	0.6	6	0.6	0	0	0	0	0
Totals:	292	6.8	136	4.905	44	1.895	0	62	50

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		Abstain	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	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A
1	Berkshire Hathaway Energy -	Terry Harbour		None	N/A

	MidAmerican Energy Co.				
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Abstain	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	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	Chris de Graffenried		Abstain	N/A
1	CPS Energy	Glenn Pressler		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		None	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	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	Third-Party Comments
1	Georgia Transmission	Jason Snodgrass		Negative	Third-Party Comments

	Corporation				
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	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		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		None	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	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	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		None	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	Mike ONeil		Affirmative	N/A

	Light Co.				
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	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Abstain	N/A
1	Platte River Power Authority	John Collins		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		Negative	Third-Party Comments
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	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	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		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		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		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	Third-Party Comments
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		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Negative	Third-Party Comments

2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
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	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Valerie Reis		None	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi	Pat Harrington	Abstain	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		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		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	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Abstain	N/A

3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Third-Party Comments
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	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	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		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
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		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		None	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	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		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Comments Submitted
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		Abstain	N/A
3	Seattle City Light	Dana Wheelock		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		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		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	WEC Energy Group, Inc.	James Keller		Negative	Third-Party Comments
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted

4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
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		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Third-Party Comments
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	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		Affirmative	N/A

4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	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	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Abstain	N/A
5	Bonneville Power Administration	Francis Halpin		Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs	Jeff Icke		Affirmative	N/A

	Utilities				
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Third-Party Comments
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Abstain	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Third-Party Comments
5	Florida Municipal Power Agency	David Schumann		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		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
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	Dixie Wells		Abstain	N/A

	River Authority				
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	NB Power Corporation	Rob Vance		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		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Omaha Public Power District	Mahmood Safi		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	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		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 Gill-Zobitz	Joe Tarantino	Affirmative	N/A

5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Seattle City Light	Mike Haynes	Ginette Lacasse	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Third-Party Comments
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Negative	Third-Party Comments
5	Westar Energy	stephanie johnson		Abstain	N/A
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A

6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Abstain	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Abstain	N/A
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Third-Party Comments
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	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Iberdrola - New York State Electric and Gas Corporation	Julie King		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A

6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	None	N/A
6	Muscatine Power and Water	Ryan Streck		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		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments
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		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	Third-Party Comments
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	Trudy Novak		Abstain	N/A

	Cooperative, Inc.				
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	Third-Party Comments
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Megan Wagner		Abstain	N/A
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Negative	Comments Submitted
8	David Kiguel	David Kiguel		Negative	Third-Party Comments
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		None	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	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

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/43)
Ballot Name: 2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 AB 2 ST
Voting Start Date: 1/15/2016 12:01:00 AM
Voting End Date: 1/26/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 249
Total Ballot Pool: 303
Quorum: 82.18
Weighted Segment Value: 68.01

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	79	1	42	0.724	16	0.276	0	6	15
Segment: 2	10	0.9	2	0.2	7	0.7	0	1	0
Segment: 3	69	1	35	0.745	12	0.255	0	6	16
Segment: 4	21	1	14	0.778	4	0.222	0	0	3
Segment: 5	63	1	33	0.702	14	0.298	0	6	10
Segment: 6	51	1	25	0.676	12	0.324	0	5	9
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	1	0.1	1	0.1	0	0	0
Segment:	2	0.1	1	0.1	0	0	0	0	1

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9									
Segment: 10	6	0.6	6	0.6	0	0	0	0	0
Totals:	303	6.8	159	4.624	66	2.176	0	24	54

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	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
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	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A

1	Beaches Energy Services	Don Cuevas		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	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	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		None	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	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy -	William Smith		Negative	Third-Party

	FirstEnergy Corporation				Comments
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	Third-Party Comments
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	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Iberdrola - Central Maine Power Company	Joe Turano		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Negative	Comments Submitted
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	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	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	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		None	N/A
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	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Abstain	N/A
1	Platte River Power Authority	John Collins		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		Negative	Third-Party Comments
1	PSEG - Public Service Electric and	Joseph Smith		Negative	Comments Submitted

	Gas Co.				
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	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		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative	Comments Submitted
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		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A

1	Westar Energy	Kevin Giles		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Dean Schiro		Negative	Third-Party Comments
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		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
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	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Valerie Reis		None	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi	Pat Harrington	Abstain	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		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		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	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	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
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy -	Theresa Ciancio		Negative	Third-Party

	FirstEnergy Corporation				Comments
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Grand River Dam Authority	Jeff Wells		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		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	JEA	Garry Baker		None	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	Scott Miller	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		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	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		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		None	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Thomas Ward		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	Comments Submitted
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		Abstain	N/A
3	Seattle City Light	Dana Wheelock		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	Southern Indiana Gas and Electric Co.	Jim Cox		Affirmative	N/A

3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Negative	Comments Submitted
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		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	Westar Energy	Bo Jones		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Michael Ibold		Negative	Third-Party Comments
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	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
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		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Third-Party Comments

4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	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		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
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	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
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		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	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	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Third-Party Comments
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Abstain	N/A
5	Exelon	Vince Catania		Abstain	N/A

5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Third-Party Comments
5	Florida Municipal Power Agency	David Schumann		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		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
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	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		Negative	Comments Submitted
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Omaha Public Power	Mahmood Safi		Affirmative	N/A

	District				
5	OTP - Otter Tail Power Company	Cathy Fogale		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	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	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		Affirmative	N/A
5	Seattle City Light	Mike Haynes	Ginette Lacasse	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Negative	Comments Submitted
5	Talen Generation, LLC	Donald Lock		Negative	Third-Party Comments
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A

5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	Westar Energy	stephanie johnson		Negative	Third-Party Comments
6	AEP - AEP Marketing	Edward P Cox		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	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		Abstain	N/A
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments

6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Third-Party Comments
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	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Iberdrola - New York State Electric and Gas Corporation	Julie King		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	None	N/A
6	Muscatine Power and Water	Ryan Streck		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	Joe O'Brien		Affirmative	N/A

	Indiana Public Service Co.				
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments
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		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	Third-Party Comments
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	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		None	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Negative	Comments Submitted
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	Third-Party Comments

6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Negative	Third-Party Comments
6	Westar Energy	Megan Wagner		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Negative	Comments Submitted
8	David Kiguel	David Kiguel		Negative	Third-Party Comments
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		None	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	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

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NERC Balloting Tool (/)

Dashboard (/) Users Ballots Surveys Legacy SBS (https://standards.nerc.net/)

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/43)
Ballot Name: 2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 Non-binding Poll AB 2 NB
Voting Start Date: 1/15/2016 12:01:00 AM
Voting End Date: 1/26/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 218
Total Ballot Pool: 266
Quorum: 81.95
Weighted Segment Value: 81.76

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	65	1	33	0.846	6	0.154	0	16	10
Segment: 2	10	0.5	2	0.2	3	0.3	0	4	1
Segment: 3	62	1	28	0.848	5	0.152	0	14	15
Segment: 4	19	1	11	0.846	2	0.154	0	3	3
Segment: 5	57	1	21	0.75	7	0.25	0	19	10
Segment: 6	43	1	19	0.826	4	0.174	0	12	8
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment:	2	0.1	1	0.1	0	0	0	0	1

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9									
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	266	6.2	121	5.017	27	1.183	0	70	48

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		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	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A
1	Berkshire Hathaway Energy -	Terry Harbour		None	N/A

	MidAmerican Energy Co.				
1	Bonneville Power Administration	Donald Watkins		Abstain	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Abstain	N/A
1	CPS Energy	Glenn Pressler		Negative	Comments Submitted
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		None	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	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	Comments Submitted
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	Comments Submitted
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	Abstain	N/A

1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		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		None	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	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	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
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 -	Terri Pyle		Negative	Comments

	Oklahoma Gas and Electric Co.				Submitted
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	Platte River Power Authority	John Collins		Abstain	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		Abstain	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
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
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		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma,	John Merrell		Affirmative	N/A

	WA)				
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		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	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		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	None	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Valerie Reis		None	N/A
3	Avista - Avista	Scott Kinney		None	N/A

	Corporation				
3	BC Hydro and Power Authority	Faramarz Amjadi	Pat Harrington	Abstain	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		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		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	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California	Romel Aquino		None	N/A

	Edison Company				
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	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	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		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public	Ramon Barany		Affirmative	N/A

	Service Co.				
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		None	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	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		Abstain	N/A
3	Seattle City Light	Dana Wheelock		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		Affirmative	N/A
3	Tallahassee Electric	John Williams		Affirmative	N/A

	(City of Tallahassee, FL)				
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Westar Energy	Bo Jones		Abstain	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		Abstain	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento	Michael Ramirez	Joe Tarantino	Affirmative	N/A

	Municipal Utility District				
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Abstain	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	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	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Bonneville Power Administration	Francis Halpin		Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
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		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	David Schumann		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		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
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	Dixie Wells		Abstain	N/A

	River Authority				
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		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	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	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		Affirmative	N/A
5	Seattle City Light	Mike Haynes	Ginette Lacasse	Affirmative	N/A
5	Seminole Electric	Brenda Atkins		Abstain	N/A

	Cooperative, Inc.				
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	Westar Energy	stephanie johnson		Abstain	N/A
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Abstain	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A

6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
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	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	None	N/A
6	Muscatine Power and Water	Ryan Streck		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		Affirmative	N/A

6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		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		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		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		Abstain	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		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		Abstain	N/A
6	Westar Energy	Megan Wagner		Abstain	N/A

8	David Kiguel	David Kiguel		Abstain	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		None	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	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/43)
Ballot Name: 2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 Non-binding Poll AB 2 NB
Voting Start Date: 1/15/2016 12:01:00 AM
Voting End Date: 1/26/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 222
Total Ballot Pool: 274
Quorum: 81.02
Weighted Segment Value: 76.27

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	69	1	35	0.778	10	0.222	0	11	13
Segment: 2	10	0.5	2	0.2	3	0.3	0	4	1
Segment: 3	64	1	30	0.769	9	0.231	0	9	16
Segment: 4	19	1	12	0.8	3	0.2	0	1	3
Segment: 5	57	1	27	0.73	10	0.27	0	11	9
Segment: 6	45	1	22	0.759	7	0.241	0	7	9
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment:	2	0.1	1	0.1	0	0	0	0	1

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9									
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	274	6.2	135	4.735	42	1.465	0	45	52

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	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
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	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A

1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	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		Negative	Comments Submitted
1	Dairyland Power Cooperative	Robert Roddy		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		None	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	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	Comments Submitted
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks,	Payam Farahbakhsh	Oshani	Negative	Comments

	Inc.		Pathirane		Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	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		None	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	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	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	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
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	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	Platte River Power Authority	John Collins		Abstain	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		Abstain	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
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
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		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A

1	Seattle City Light	Pawel Krupa		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative	Comments Submitted
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		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
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		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	None	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection,	Mark Holman	William Temple	Negative	Comments

	L.L.C.				Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Valerie Reis		None	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi	Pat Harrington	Abstain	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		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		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	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	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
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Grand River Dam Authority	Jeff Wells		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		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Negative	Comments Submitted
3	JEA	Garry Baker		None	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	Stephen Pogue		Affirmative	N/A

	Power Cooperative				
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	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		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
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	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		None	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		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	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento	Rachel Moore	Joe Tarantino	Affirmative	N/A

	Municipal Utility District				
3	Santee Cooper	James Poston		Abstain	N/A
3	Seattle City Light	Dana Wheelock		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		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		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		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A

4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Keys Energy Services	Stanley Rzad		Affirmative	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		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Abstain	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
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	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A

5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
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	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	David Schumann		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		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
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	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		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	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	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		Affirmative	N/A
5	Seattle City Light	Mike Haynes	Ginette Lacasse	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	Westar Energy	stephanie johnson		Negative	Comments Submitted
6	AEP - AEP Marketing	Edward P Cox		Affirmative	N/A

6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	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	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
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	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lincoln Electric	Eric Ruskamp		Abstain	N/A

	System				
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	None	N/A
6	Muscatine Power and Water	Ryan Streck		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		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		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		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		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	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Negative	Comments Submitted
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		Negative	Comments Submitted
8	David Kiguel	David Kiguel		Abstain	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		None	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	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

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Comment Report

Project Name:	2009-02 Real-time Reliability Monitoring and Analysis Capabilities | IRO-018-1 & TOP-010-1
Comment Period Start Date:	12/10/2015
Comment Period End Date:	1/26/2016
Associated Ballots:	2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 AB 2 ST 2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 Non-binding Poll AB 2 NB 2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 AB 2 ST 2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 Non-binding Poll AB 2 NB

There were 38 sets of responses, including comments from approximately 33 different people from approximately 31 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the changes made by the SDT to draft standard IRO-018-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

2. Do you agree with the changes made by the SDT to draft standard TOP-010-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

3. Do you agree with the revised Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

4. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

5. Provide any additional comments for the SDT to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	ACES Power Marketing	1	RFC
					Ginger Mercier	ACES Power Marketing	1,3	SERC
					Michael Brytowski	ACES Power Marketing	1,3,5,6	MRO
					John Shaver	ACES Power Marketing	4,5	WECC
					John Shaver	ACES Power Marketing	1	WECC
					Shari Heino	ACES Power Marketing	1,5	TRE
					Bill Hutchison	ACES Power Marketing	1	SERC
					Mark Ringhausen	ACES Power Marketing	3,4	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RFC,SERC	Duke Energy	Doug Hils	Duke Energy	1	RFC
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RFC
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

MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Tony Eddleman	MRO	1,3,5	MRO
					Amy Casucelli	MRO	1,3,5,6	MRO
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Robert Schaffeld	Southern Company - Southern Company Services, Inc.	1	SERC
					John Ciza	Southern Company - Southern Company Services, Inc.	6	SERC
					R Scott Moore	Southern Company - Southern Company Services, Inc.	3	SERC
					William Shultz	Southern Company - Southern Company Services, Inc.	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no ISO-NE IESO Dominion	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

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no ISO-NE IESO Dominion	Randy MacDonald	Northeast Power Coordinating Council	2	NPCC
					Wayne Sipperly	Northeast Power Coordinating Council	4	NPCC
					David Ramkalawan	Northeast Power Coordinating Council	4	NPCC
					Glen Smith	Northeast Power Coordinating Council	4	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	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
					Silvia Parada Mitchell	Northeast Power Coordinating Council	4	NPCC
					Michael Forte	Northeast Power Coordinating Council	1	NPCC
					Sylvain Clermont	Northeast Power Coordinating Council	1	NPCC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no ISO-NE IESO Dominion	Si Truc Phan	Northeast Power Coordinating Council	2	NPCC
					Kelly Silver	Northeast Power Coordinating Council	3	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
					Robert J Pellegrini	Northeast Power Coordinating Council	1	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
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP
					Jason Smith	Southwest Power Pool, Inc. (RTO)	2	SPP
					Jim Nail	Southwest Power Pool, Inc. (RTO)	3,5	SPP
					Mike Kidwell	Southwest Power Pool, Inc. (RTO)	1,3,5	SPP
					Bo Jones	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP
					Allan George	Southwest Power Pool, Inc. (RTO)	1	SPP
					Robert Hirchak	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP

1. Do you agree with the changes made by the SDT to draft standard IRO-018-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern believes that the criteria in R1.1 should be limited to the RC's ability to monitor and assess the current/expected condition of its RC area within the capabilities of its monitoring tools.

Each RC has the inherent responsibility to protect the integrity of the system in its RC area and contribute to the overall integrity of Interconnection as required by other approved reliability standards. The NERC approved IRO-002-4, IRO-010-2, TOP-003-3 and TOP-004 standards requires the RCs and TOPs to have monitoring tools and capabilities to assess system conditions in its area and to perform next day and real time reliability assessments to identify/mitigate potential issues that could have an adverse impact on reliability. Moreover, Southern asserts that the capability to maintain an accurate model along with the required telemetry is already being assessed at the certification stage, and that maintenance of such capability does not need to be assessed on an ongoing basis as adequate data quality is required to perform the assessments required by the aforementioned standards.

Since the RC is constantly evaluating the quality of data received to ensure it has an accurate state of system conditions to perform real time assessments, through the same processes demonstrated during certification. Southern believes that the reliability goals of maintaining adequate data, tools and situational awareness are accomplished via the IRO-010 and TOP-003-3 NERC reliability standards and to impose this new standard focusing on data quality would only serve as administrative in nature and would not provide any substantial increases in reliability.

Given that Southern disagrees with the reliability need for this standard, Southern notes that the detailed requirements (R1.1.1, etc…)regarding assessing data quality, on a point by point basis, was moved to the technical background section of the purposed standard, which is helpful as long as the RSAWs developed doesn't incorporate this "one size fits all" approach for assessing data quality.

Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

We continue to disagree with the need to create Reliability Standards (this and TOP-010-1) to stipulate the requirements for having processes in place to ensure data quality and real-time analysis capability, and adequate alarming system to alert operators of suspicious data or analysis capability. These processes are fundamental to enabling the RC, TOP and BA perform their reliability tasks and meet applicable standard requirements. Data quality, real-time analysis capability and alarming system must be demonstrated during the certification process, and maintained at all times. We continue to urge NERC and the SDT to place these requirements in the Organization Certification Requirements, if they are not already explicitly stipulated.

Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	

PJM does not believe this standard is necessary. RC, BA & TOP entities currently have adequate tools for real-time monitoring and analysis. The existing Standards (i.e., IRO, TOP, & BAL) adequately define what needs to be monitored by each entity without defining the tools. Creating new requirements will not increase the reliability of the BES.

Additionally, some of the new proposed requirements (IRO-018-1 Req. 1, TOP-010-1 Req. 1) state:

Each RC, BA & TOP shall implement an Operating Process to address the *quality* of the Real-time data… the term *quality* is ambiguous and subjective. This term needs to be defined. Similar to Requirement 2, the terms *indications of quality* needs to be defined. If not defined, it could result in varying interpretations throughout the industry.

Lastly, the NERC Operating Reliability Subcommittee (ORS) has drafted a Reliability Guideline, “Loss of Real-Time Reliability Tools Capability / Loss of Equipment Significantly Affecting ICCP Data.” This guideline will help ensure that tools are adequate and if they are degraded for any reason, the potentially impacted entities are aware and can take action if needed.

PJM supports the comments submitted by the ISO/RTO Council Standards Review Committee.

Likes 1	PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
Dislikes 0	
Response	
Kathleen Goodman - Kathleen Goodman	
Answer	No
Document Name	
Comment	

The SRC fails to see the reliability risk that this project is intending to address. The August 14 Blackout as well as the 2011 Southwest Outage have been thoroughly and exhaustively investigated, reported upon, and the root causes mitigated appropriately. Those investigations did not indicate a lack of continent-wide ability to address those root causes – which would be the basis upon a NERC continent-wide reliability standard is needed to address a reliability "gap". Therefore, pointing to the need for this project based on mitigated, historical events falls short of identifying the reliability risk that this is intended to "fix." If, for example, WECC continues to have a vested interest in further mitigating the 2011 Southwest Outage through standard development, we suggest this project be migrated into a regional standard for WECC. Lastly, the SRC believes that, absent a Standard specific for tools, a RC, TOP, or BA would, in fact, have violations of existing operational Requirements if they do not provide adequate monitoring and tools to their operators (i.e. other "things" would happen).

Further, the Requirements as written, "…to address the quality of the Real-time data necessary…" are ambiguous, lack consensus about how to measure, and do not rise to the level of a NERC Standard.

This proposed project appears to be well-suited for a guideline document as opposed to a Standard as the proposed requirements address the quality and availability aspects of data and tools for system analysis rather than what's needed to monitor and assess system performance (which are already covered by other standards). As written, the standards appears to intend to stipulate "how" not "what" (*i.e.*, they do not appear to be a results-based standards). The SRC believes that the existing Standards (*i.e.*, IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (*i.e.*, without defining the "how"), which is appropriate. In the alternative, this could be considered a process to be used for Certifying new entities, in line with a methodology developed by the ERO and registered entities for assessing adequacy of tools for addressing the "quality" of real-time data and tools, for assurance that RC, BA and TOPs have the ability to monitor and assess system performance appropriately in accordance with existing, performance-based Standards Requirements.

The SRC notes that the tools available to operators have progressed well beyond those available in 2003. If defined tools would have been hardcoded in a standard at that time, it would have limited focus and investment to those things that were in the standard. Further, expanding on our point above, the SRC believes that the "what" regarding tools is more appropriately captured in the certification expectations for BAs, RCs, and TOPs. Additionally, it would be appropriate for Regions to evaluate tools as part of the Registered Entity's Inherent Risk Assessment (IRA). This would include the scope of tools, backups, etc. and would provide an adaptable approach that would encourage continuous improvement.

Additionally, the SRC recommends that NERC coordinate with the NATF to encourage inclusion of an ongoing "care and feeding" of tools evaluation and information sharing in their efforts with the provision that they make information on good practices available to the wider NERC community so that non-members can learn from the innovation of others.

Finally, to avoid these issues in the future and to support communicating to FERC when a Standard is not needed and another tool is more suitable, the SRC suggests that future SARs be voted on by industry to determine whether they should proceed as a Standards project or another means is a more appropriate method through which to achieve the SAR's objective.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy

Answer	No

Document Name	
Comment	

Duke Energy suggests changes to the language of the requirements and sub-requirements which would make the standard less vague, and more concise. We recommend the following revisions:

R1:

-Modify R1 to state: *"Each Reliability Coordinator shall develop and implement an Operating Process or Operating Procedure to address…"*

We feel that this closes a gap wherein the standard requires an entity to implement a Process or Procedure, but never requires an entity to develop one in the first place.

We believe that R1.1 and R1.2 are similar in nature, and would be better suited as one requirement. We recommend the same revision for R2.1 and R2.2. We suggest the following:

-Combine R1.1 and R1.2 to state: *"Criteria for and display of quality of Real-time data to System Operator."*

R2:

-Modify R2 to state: *"Each Reliability Coordinator shall develop and implement an Operating Process or Operating Procedure to address…"*

We feel that this closes a gap wherein the standard requires an entity to implement a Process or Procedure, but never requires an entity to develop one in the first place.

We believe that R2.1 and R2.2 are similar in nature, and would be better suited as one requirement. We suggest the following:

-Combine R2.1 and R2.2 to state: *"Criteria for and display of quality of Real-time data to System Operator."*

Also, we recommend that the requirement be reworded to more closely resemble the rationale. The rationale points out that the RC shall have Processes or Procedures that address issues related to the quality of analysis results used for Real-time Assessments. The language of R2 states that an RC must have Processes or Procedures to address the quality of analysis used in its Real-time Assessments. We feel that adding the word "results" in the requirement decreases possible ambiguity that is currently present in this standard. It is the quality of the results that is paramount, and should be the focus, rather than the quality of the analysis itself. (See out language suggestion after the comment below.)

Next, Duke Energy recommends that R2 should include a provision that an RC should include in their procedure some specification as to what constitutes a "quality issue" (see R2.3) that an RC must take action to resolve. Without having those specifications, it would be difficult to determine what issues necessitate actions and which ones do not. We suggest the following revision to R2:

-Modify R2 to state: *"Each Reliability Coordinator shall develop and implement an Operating Process or Operating Procedure to address the quality analysis results, and include criteria to define levels of material impact, used in its Real-time Assessments."*

Lastly, Duke Energy suggests that R3 should be revised to more closely align with the rationale. When reading the rationale, it is clear that the heart of this requirement is having an alarm process monitor capability, and not necessarily the alarm process monitor itself. We recommend using the language found in the rationale which more clearly state the intent of the requirement. We suggest the following:

-Modify R3 to state: *"Each Reliability Coordinator shall have an alarm process monitoring capability that provides notification(s) to its System Operators…"*

Likes 0	
Dislikes 0	
Response	

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	

The Rational for R3 mentions that the alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

What happens when all procedures and processes are followed properly and SCADA system fails because of an IT problem. In another words, RC must not be attributable when SCADA systems fail because of an IT problem. The standard should also consider accountability of the SCADA supplier.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

(1) We feel the language within Requirements R1 and R2 are vague and should not require criteria for evaluating data quality and analysis that could be too ambiguous and unenforceable. These requirements need to identify what real-time data and analysis are necessary to perform monitoring and assessment functions, and identify the specifications necessary to maintain reliability. The SDT should clarify the meaning of "quality," and incorporate this explanation in the standard's Guidelines and Technical Basis or Rationale sections. Without a minimum criteria specified, we feel this does not provide enough information to make an objective determination for an auditor. Furthermore, we suggest adding references to Part 1.3 and Part 2.3 that mitigation actions should be initiated within 30 minutes. We feel these references align the failure to implement actions with other mitigation actions required.

(2) Requirement R3 expects the RC to have evidence that it has an alarm process monitor that provides failure notifications to System Operators. We feel this language is redundant with many requirements of Reliability Standard IRO-002-2. For instance, Requirement R4 of IRO-002-2 states the RC "shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas." Moreover, Requirement R7 of IRO-002-2 states "Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area." While requirements R1 and R2 of the proposed standard, IRO-018-1, are concerned with quality expectations of data and analysis, respectively, Requirement R3 identifies a tool or application that the RC must own and operate. In order to meet the various requirements of IRO-002-2, the RC would already be required to own and operate such applications. Hence, we recommend the SDT remove requirement R3 of the proposed standard.

(3) We continue to have concerns that these requirements only focus on System Operators. We feel that an auditor may not interpret the standard to allow other employees, such as EMS Engineers, to mitigate data or analytical errors. According to the NERC Glossary Term, a System Operator is one "who operates or directs the operation of the Bulk Electric System (BES) in Real-time." We recommend the SDT clarify that these requirements can apply to other employees.

Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
The Rational for R3 mentions that the alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor. What happen when all procedures and processes are followed properly and SCADA system fails because of an IT problem? In another words, RC must not be attributable when SCADA systems fail because of an IT problem. The standard should also consider accountability of the SCADA supplier	
Likes 0	
Dislikes 0	
Response	
John Brockhan - CenterPoint Energy Houston Electric, LLC - 1	
Answer	No
Document Name	
Comment	
See comments for Q2.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	Unofficial_Comment_Form_2009-02_121015_ERCOT draft_ssolis_eha_nb.docx
Comment	

Comments: ERCOT continues to be concerned that the proposed standard is too prescriptive and goes beyond the associated FERC directive regarding a requirement addressing "capabilities." In particular, these standards were developed to address operator awareness of tool or other outages that could impact real-time monitoring.

Further, several of the requirements involve many more entities beyond the Reliability Coordinators and, absent a requirement for coordination, participation, and action in response to the Reliability Coordinator's identification of an issue, the proposed standard will not achieve its intended objective as written. This is extremely challenging (R1.3) because the majority of issues related to poor data quality or invalid analysis tool solutions can only be resolved by parties outside of the Reliability Coordinator (e.g facility owners, telecom companies, etc.)

Additionally, real-time data and monitoring capabilities are critical to the certification of a Reliability Coordinator and are not "dynamic." Because such "capabilities" are complex, require coordination and inputs from other entities, and are key to the continued performance of a Reliability Coordinator's duties, they are not subject to frequent change and therefore likely do not need continued monitoring and assessment.

Finally, several other reliability standards and associated requirements are contingent upon the availability of real-time tools and data, and these other standards and requirements are subject to the compliance monitoring and enforcement program. ERCOT would recommend that requirements addressing capabilities be utilized as part of certification review and not as a reliability standard subject to the compliance monitoring and enforcement program.

Should NERC continue this project, however, ERCOT recommends the following language adjustments to Requirement R1.3. No matter what the SDT *intends* the language to mean, this requirement language may still be read to mean the RC's Operating Process or Operating Procedure should be written to actively resolve data quality issues even though the ability to resolve data issues may lie with another party. Accordingly, ERCOT recommends:

R1.3 current language: "Actions to resolve Real-time data quality issues with the entity(ies) responsible for proving the data when data quality affects Real-time Assessments."

R1.3 ERCOT suggested language: "Actions to notify the entity(ies) responsible for providing data of any Real-time data quality issue affecting Real-time Assessments."

This language aligns with the objective communicated by the SDT, aligns with what is in practice today, aligns with the SDT concept that IRO-010 and TOP-005/003 require data providers to address data quality issues, and is within the capability of the Reliability Coordinator to perform. This language is also consistent with the numerous examples within the NERC Reliability Standards where an entity is required to notify other entities that are responsible for or have an obligation to take actions where the notifying entity cannot or does not perform the reliability task.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE IESO Dominion	
Answer	Yes
Document Name	
Comment	

We support the draft standard IRO-018-1.

R2 2.3 Instead of "Action to resolve analysis quality issues affecting its Real-time Assessments", suggest change the language to "Action to resolve quality analysis issues affecting its Real-time Assessments."

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

We suggest to the drafting team to mention more information in the rationale box pertaining to Requirement R1 and its sub-part 1.1 on the expectations for the criteria in reference to evaluating the quality of the real-time data. Additionally, our review group would suggest mentioning the criteria examples spoken of in the drafting team's webinar in this section of the rationale box. The review group's opinion of this is….the criteria examples will give the industry a foundation on how to use various Real-time scenarios to structure their Operational Process and/or Operational Procedure.

In our opinion, Requirement R1 sub-part 1.3 rationale box information (last paragraph) doesn't match the proposed language for that particular section of the Requirement. The Rationale information doesn't clearly state what documentation contains the 'scope of data point information' this proposed language will help clarify. We would ask are you referring to the SAR, or the RTBPTF Report or could it be the FERC Directive? Our review group would also suggest mentioning the specific document(s) in the rationale section so there will be no misconception on what documentation contains the scope in reference to the data points and how those points should be addressed when providing evidence during an auditing process.

As for Requirement R2, we would suggest to the drafting team to include the examples provided in their presentation to the rationale section. We feel this information will help give some clarity on what the expectations are for the industry pertaining to Requirement R2.

For Requirement R3, we suggest that the drafting team include some proposed language that suggests including the 'alarm process monitor that provide modification' into their Operational Process or Operation Procedure. We feel the current language suggests that this process doesn't need to be included in the previously mentioned documentation which could lead to interpretation issues from our perspective.

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	

In general, Texas RE agrees with the changes made by the SDT to draft standard IRO-018-1. However, Texas RE provides the following comments or suggestions to the proposed standard:

- Texas RE suggests the SDT consider explicitly stating real-time monitoring in addition to real-time assessments in R1.3. For example, "Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time monitoring and Real-time Assessments. In addition, Texas RE would like to highlight that Texas RE is concerned there is no definitive timeframe provided associated with the actions to resolve issues which may lead to a reliability gap due to a myriad of approaches taken by registered entities. Texas RE supports the RTBPTF recommendations related to real-time monitoring. Specifically, for telemetry data systems:

1) Increase the minimum update frequency for operational reliability data

from once every 10 minutes to once every 10 seconds.16

2) Standardize the procedures, processes, and rules governing key data

exchange issues.17

3) Institute a requirement for data availability from ICCP or other

equivalent systems, based on the ratio of "good" data received (as defined

by data quality codes) to total data received. The ratio must exceed 99

percent for 99 percent of the sampled periods during a calendar month. In

addition, the ratio must not be less than 99 percent for any 30 consecutive

minutes.

4) Establish minimum response times for restoration of data exchange

between control centers following the loss of a data link or other problems

within the source system. As part of this requirement, a trouble-resolution

process standard must be developed that requires all entities responsible

for management and maintenance of ICCP or equivalent systems to

identify, with data recipients that could be affected by a loss of data

exchange capability, a mutually agreeable restoration target time. The

standard process must also include service-restoration escalation

procedures and prioritization criteria.

- Texas RE noticed an inconsistency in language between the standard requirement language and the rationale discussion for Requirement 1 and

Requirement 2 which states, “The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to *operating personnel*.” Unfortunately, “operating personnel”, is not a defined term and the Requirements specifically states “System Operator”. Texas RE recommends that the rational language be changed to be consistent with the standard requirements.

- Texas RE is concerned the data retention for R2 is a rolling 30 days while the retention period for R1 is the current calendar year and one previous calendar year with the exception of operator logs and voice recording which shall be retained or a minimum of 90 calendars days. Texas RE inquires as to why there is a difference in the evidence retention period even though there is very little difference in the measures? Texas RE recommends an evidence retention period of a year for both R1 and R2 because there is no basis to distinguish actions to address errors in data inputs (R1) and the analysis of the data inputs (R2) and the longer time frame of a year would give the entity more time to resolve data issues.

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

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	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 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	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Kenny - Eversource Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Not applicable to BPA.	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane	
Answer	
Document Name	
Comment	

IRO-018-1 is not applicable to Hydro One. However, Hydro One Networks Inc. would like to point out that R1.2 should specify, that the RC's Operating Process or Operating Procedure which is to include actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data, should include a mutually agreed upon schedule and actions.

Likes 0	
Dislikes 0	

Response

2. Do you agree with the changes made by the SDT to draft standard TOP-010-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	
Comment	
The language is too ambiguous.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

Comments: For purposes of this comment, ERCOT incorporates all of its above comments regarding IRO-018-1. As with R1.3 in IRO-018-1, ERCOT is concerned that certain language in TOP-010-1 could be read to suggest that the RC must resolve Real-time data quality issues, when in fact the ability to resolve data issues may lie with another party. Consistent with its suggested revisions to R1.3 in IRO-018-1, ERCOT recommends the following changes to R1.3 and R2.3 in TOP-010-1:

R1.3 current language: “Actions to resolve Real-time data quality issues with the entity(ies) responsible for proving the data when data quality affects Real-time Assessments.”

R1.3 ERCOT suggested language: “Actions to notify the entity(ies) responsible for providing data of any Real-time data quality issue affecting Real-time Assessments.”

And

R2.3 current language: “Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.”

R2.3 ERCOT suggested language: “Actions to notify the entity(ies) responsible for providing data of any Real-time data quality issue affectings its analysis functions.”

Likes 0	
Dislikes 0	

Response

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1

Answer	No
Document Name	

Comment

CenterPoint Energy understands recommendations for the scope of this project originated from the 2011 Southwest Outage Report as well as FERC directives in Order 693, however with the vast improvement in technologies involved with monitoring and analysis capabilities over the last 10 years, these recommendations as well as the scope of this project is potentially outdated. CenterPoint Energy is concerned that compliance with Requirements in TOP-010-1 could represent a documentation burden without providing a measureable benefit to reliability. The main focus of the directives and recommendations referenced above appear to be more related to real-time analysis tools rather than quality of data. CenterPoint Energy believes and feels the industry would benefit more from, reducing the scope of the Standard to those data quality issues that negatively impact real-time analysis and assessments. CenterPoint Energy recommends the SDT delete Parts 1.1, 1.2, 2.1, and 2.2.

Likes 0	

Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
What happen when all procedures and processes are followed properly and SCADA system fails because of an IT problem? In another words, BA or TOP must not be attributable when SCADA systems fail because of an IT problem. The standard should also consider accountability of the SCADA supplier	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - City and County of San Francisco - 1,5	
Answer	No
Document Name	
Comment	
The draft version of Requirement R4. reads as follows: *Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.* We believe greater clarity could be brought to this requirement by modifying two awkward terms, "alarm process monitor" and "monitoring alarm processor", as follows: *Each Transmission Operator and Balancing Authority shall monitor its Real-time monitioring alarm system and provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm system has occurred.*	
Likes 0	
Dislikes 0	
Response	
Meghan Ferguson - Meghan Ferguson	
Answer	No

Document Name	
Comment	

The changes made to R1 are helpful in clarifying the scope of data included in this requirement however the term “quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments” would still imply all data specified per TOP-003 as all data specified will be the data used in Real time Assessment and therefore will require TOP to take action on any failed data point. Also the term real time monitoring is not a defined term and should be removed.

In addition to the above comments, ITC Holdings agrees with the comments submitted by the SPP Standards Review Group. A copy of SPP's comments are provided below.

We suggest to the drafting team to mention more information in the rationale box pertaining to Requirement R1 and its sub-part 1.1 on the expectations for the criteria in reference to evaluating the quality of the real-time data. Additionally, our review group would suggest mentioning the criteria examples spoken of in the drafting team's webinar in the rationale box of this section. The review group’s opinion of this is….the criteria examples will give the industry a foundation on how to use various Real-time scenarios to structure their Operational Process or Operational Procedure.

In our opinion, Requirement R1 sub-part 1.3 rationale box information (last paragraph) doesn’t match the proposed language for that particular section of the Requirement. The Rationale information doesn’t clearly state what documentation contains the ‘scope of data point information’ this proposed language will help clarify. We would ask are you referring to the SAR, or the RTBPTF Report or could it be the FERC Directive. Our review group would suggest mentioning the specific document(s) in the Rationale Section so there will be no miss conception on what documentation contains the scope in reference to the data points and how those points should be addressed when providing evidence during an auditing process.

As for Requirement R2, we would suggest to the drafting team to include the examples provide in their presentation to the Rationale Section. We feel this information will help give some clarity on what the expectations are for the industry pertaining to Requirement R2.

For Requirement R4, we would suggest they drafting team would include some proposed language that suggests including the ‘alarm process monitor that provide modification’ into their Operational Process or Operation Procedure. We feel the current language suggests that this process doesn’t need to be included in the previously mentioned documentation which could lead to interpretation issues from our perspective.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	
Comment	

(1) We feel the language within Requirements R1 and R3 are vague and should not require criteria for evaluating data quality and analysis that could be too ambiguous and unenforceable. These requirements need to identify what real-time data and analysis are necessary to perform monitoring and assessment functions, and identify the specifications necessary to maintain reliability. The SDT should clarify the meaning of "quality," and incorporate this explanation in the standard's Guidelines and Technical Basis or Rationale sections. Without a minimum criteria specified, we feel this does not provide enough information to make an objective determination for an auditor. Furthermore, we suggest adding references to Part 1.3 and Part 3.3 that mitigation actions should be initiated within 30 minutes. We feel these references align the failure to implement actions with other mitigation actions required in other reliability standards.

(2) We understand the SDT interprets the intent of requirement R4 of the industry-approved standard, BAL-005-1, to pertain to only the data necessary to calculate Reportable ACE. Moreover, the SDT feels that the proposed Requirement R2 does not create double jeopardy with BAL-005-1, and that Requirement R2 is necessary to account for other data monitored by a BA. We disagree and feel the SDT should remove this redundant requirement or identify this other data in the rationale of this requirement.

(3) The intent of Requirement R4 requires a TOP or BA to monitor the availability of its real-time monitoring alarm processor. We feel this requirement is unnecessary, as similar actions are accomplished in order to maintain compliance with other reliability requirements. For instance, Requirement R5 of TOP-006-3 states "each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions..." In order to maintain compliance with this requirement, a registered entity is obligated to notify its own personnel when they are unable to use such monitoring equipment. We recommend the SDT remove Requirement R4 from the proposed standard.

(4) We continue to have concerns that these requirements only focus on System Operators. We feel that an auditor may not interpret the standard to allow other employees, such as EMS Engineers, to mitigate data or analytical errors. According to the NERC Glossary Term, a System Operator is one "who operates or directs the operation of the Bulk Electric System (BES) in Real-time." We recommend the SDT clarify that these requirements can apply to other employees.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

How is quality defined? This is too ambiguous as written and internal discussions resulted in multiple opinions. Quality needs to be better defined within the requirement.

Likes 0	
Dislikes 0	

Response

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment	
See comments from question 1 but replacing RC for TOP and BA.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy recommends the same changes to the language in TOP-010-1 that it does for IRO-018-1.	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	

We do not believe the issues addressed by the FERC directive rise to the level of requiring a reliability standard. The intent of the directive and the resulting actions to be taken by the various entities would be better served by an official Guideline rather than a generic standard. Forcing this into a Standard result in varied interpretations and approachs to “quality” and “adequacy” that do not enhance reliability of the BES.

We believe the requirements in general could be improved to be more results based. As written, they largely will only result in identifying deficiencies after the fact when doing event analysis. An entity may have a process or procedure as required, but they could miss a piece of data or fail to identify fully the impact a quality issue may have upon their situational awareness. Simply having the process does not result in increased reliability.

Most entities already have a process in place to alarm or indicate data quality as needed to maintain reliability. Entities are already required to operate reliably, within SOLs and IROLs, etc. The creation of this standard as written would serve only to document that process and put it under auditable enforcement – with no discernible impact to maintaining reliability. In order to make this standard truly results based, there needs to be some identification of the quality level, or data quality thresholds that must be maintained in order for reliability to be maintained. Then that level (or quality of the data measurements) must be maintained per the standard.

We suggest that there needs to be more direction given by the Standard in a few areas. One is that the applicable entity should be determining a data range, time periods, number of manually entered values, etc. that can degrade analysis to the point reliability is threatened (R1.1.1-R1.1.4).

We find it problematic when an entity may not “own” the data and is simply receiving a quality flag from a sender. An entity may not receive an accurate quality flag or the quality flag is corrupted in translation over ICCP. Also, there is no requirement that the measurement devices even be of a particular accuracy. For example the quality threshold may be more narrow than the accuracy of the device.

Likes 0	
Dislikes 0	
Response	
Kathleen Goodman - Kathleen Goodman	
Answer	No
Document Name	
Comment	

same comments as under Q1 above.

Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	

PJM does not believe this standard is necessary. RC, BA & TOP entities currently have adequate tools for real-time monitoring and analysis. The existing Standards (i.e., IRO, TOP, & BAL) adequately define what needs to be monitored by each entity without defining the tools. Creating new requirements will not increase the reliability of the BES.

Additionally, some of the new proposed requirements (IRO-018-1 Req. 1, TOP-010-1 Req. 1) state:

Each RC, BA &TOP shall implement an Operating Process to address the *quality* of the Real-time data… the term *quality* is ambiguous and subjective. This term needs to be defined. Similar to Requirement 2, the terms *indications of quality* needs to be defined. If not defined, it could result in varying interpretations throughout the industry.

Lastly, the NERC Operating Reliability Subcommittee (ORS) has drafted a Reliability Guideline, "Loss of Real-Time Reliability Tools Capability / Loss of Equipment Significantly Affecting ICCP Data." This guideline will help ensure that tools are adequate and if they are degraded for any reason, the potentially impacted entities are aware and can take action if needed.

PJM supports the comments submitted by the ISO/RTO Council Standards Review Committee.

Likes 1	PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 5

Answer	No
Document Name	

Comment

We do not believe the issues addressed by the FERC directive rise to the level of requiring a reliability standard. The intent of the directive and the resulting actions to be taken by the various entities would be better served by an official Guideline rather than a generic standard. Forcing this into a Standard result in varied interpretations and approachs to "quality" and "adequacy" that do not enhance reliability of the BES. We believe the requirements in general could be improved to be more results based. As written, they largely will only result in identifying deficiencies after the fact when doing event analysis. An entity may have a process or procedure as required, but they could miss a piece of data or fail to identify fully the impact a quality issue may have upon their situational awareness. Simply having the process does not result in increased reliability.

Most entities already have a process in place to alarm or indicate data quality as needed to maintain reliability. Entities are already required to operate reliably, within SOLs and IROLs, etc. The creation of this standard as written would serve only to document that process and put it under auditable enforcement – with no discernible impact to maintaining reliability. In order to make this standard truly results based, there needs to be some identification of the quality level, or data quality thresholds that must be maintained in order for reliability to be maintained. Then that level (or quality of the data measurements) must be maintained per the standard.

We suggest that there needs to be more direction given by the Standard in a few areas. One is that the applicable entity should be determining a data range, time periods, number of manually entered values, etc. that can degrade analysis to the point reliability is threatened (R1.1.1-R1.1.4).

We find it problematic when an entity may not "own" the data and is simply receiving a quality flag from a sender. An entity may not receive an accurate quality flag or the quality flag is corrupted in translation over ICCP. Also, there is no requirement that the measurement devices even be of a particular accuracy. For example the quality threshold may be more narrow than the accuracy of the device.

Likes 0	

Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	

Comment

Same comment as for IRO-018-1. Please see our comment under Q1, above.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	

Comment

Southern believes that the criteria in R1.1 should be limited to the BA/TOP's ability to monitor and assess the current/expected condition of its RC area within the capabilities of its monitoring tools.

Each BA/TOP has the inherent responsibility to protect the integrity of the system in its BA/TOP area and contribute to the overall integrity of Interconnection as required by other approved reliability standards. The NERC approved TOP-003-3 and TOP-004 standards requires BAs/TOPs to have monitoring tools and capabilities to assess system conditions in its area and to perform next day and real time reliability assessments to identify/mitigate potential issues that could have an adverse impact on reliability. Moreover, Southern asserts that the capability to maintain an accurate model along with the required telemetry is already being assessed at the certification stage, and that maintenance of such capability does not need to be assessed on an ongoing basis as adequate data quality is required to perform the assessments required by the aforementioned standards. In addition, there are already NERC approved standards such as TOP-002-2 that currently require the BA/TOP to maintain accurate computer models for analyzing system operations.

Since the TOP is constantly evaluating the quality of data received to ensure it has an accurate state of system conditions to perform real time assessments, through the same processes demonstrated during certification, Southern believes that the reliability goals of maintaining adequate data, tools and situational awareness are accomplished via the IRO-010 and TOP-003-3 NERC reliability standards and to impose this new standard focusing on data quality would only serve as administrative in nature and would not provide any substantial increases in reliability.

Given that Southern disagrees with the reliability need for this standard, Southern notes that the detailed requirements (R1.1.1, etc…)regarding assessing data quality, on a point by point basis, was moved to the technical background section of the purposed standard, which is helpful as long as the RSAWs developed doesn't incorporate reapply this "one size fits all" approach for assessing data quality.

Likes 0	
Dislikes 0	

Response

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	No
Document Name	
Comment	

Requirements R1 and R2 apply to monitoring system conditions. Therefore Tacoma Power believes both requirements should be included in TOP-006-2 Additionally Tacoma Power believes Requirement R4 is unnecessarily redundant, providing no foreseeable improvement to reliable operation of the bulk electric system.

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

While AEP agrees with the overall approach and intent of R1, we believe that sub-Requirement R1.3 goes beyond the scope of its parent Requirement. While R1 focuses on ***addressing*** the quality of Real-time data, R1.3 requires the Transmission Operator's Operating Process or Procedure to include actions to ***"resolve"*** Real-time data quality issues when data quality affects Real-time Assessments. This is especially concerning when the "entity(ies) responsible for providing the data" are external. Neither the Transmission Operator, nor its Operating Procedure, is able to resolve data issues involving points over which they have no direct control. The entity would have control over their own analysis quality (R3), but again, not the quality of external data. In the webinar held on January 11, the drafting team inferred a different interpretation of R1.3 depending on whether or not the data is externally provided. The drafting team seemed to be saying "no, you don't need to resolve data issues for points you do not own, but you still need to document actions to resolve those data issues", etc. That seems to infer that "actions to resolve" might, in some cases, simply be *informing* the data owner of the issue rather than *remediating* issues involving the external data. While the drafting team might interpret R1.3 in this manner, there is no assurance that an auditor would have that same viewpoint. And if that is indeed the drafting team's interpretation , R1.3 does not articulate that. In this same webinar, a drafting team member eventually used the phrase "address the quality" in regards to externally provided data. AEP believes the word "address" is much more appropriate for R1.3 than "resolve", and using it would allow R1.3 to align with R1 (which already uses the word "address"). As a result, we recommend that the word "resolve" in R1.3 be replaced by "address", so that it states "Actions necessary to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments."

Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	AZPS-Comments_Question-2_Project-2009-02_Draft-2.docx
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

In general, Texas RE agrees with the changes made by the SDT to draft standard TOP-010-1. However, Texas RE provides the following comments or suggestions to the proposed standard:

- Texas RE recommends adding the Balancing Authority to the applicability of R3. Some BA tools can be considered a Real-time monitoring tool, for example, the use of SCED in this region.
- Texas RE suggests the SDT consider explicitly stating real-time monitoring in addition to real-time assessments in R1.3. For example, "Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time monitoring and Real-time Assessments. In addition, Texas RE would like to highlight that Texas RE is concerned there is no definitive timeframe provided associated with the actions to resolve issues which may lead to a reliability gap due to a myriad of approaches taken by registered entities. Texas RE supports the RTBPTF recommendations related to real-time monitoring. Specifically, for telemetry data systems:

1) Increase the minimum update frequency for operational reliability data

from once every 10 minutes to once every 10 seconds.16

2) Standardize the procedures, processes, and rules governing key data

exchange issues.17

3) Institute a requirement for data availability from ICCP or other

equivalent systems, based on the ratio of "good" data received (as defined

by data quality codes) to total data received. The ratio must exceed 99

percent for 99 percent of the sampled periods during a calendar month. In

addition, the ratio must not be less than 99 percent for any 30 consecutive minutes.

4) Establish minimum response times for restoration of data exchange between control centers following the loss of a data link or other problems within the source system. As part of this requirement, a trouble-resolution process standard must be developed that requires all entities responsible for management and maintenance of ICCP or equivalent systems to identify, with data recipients that could be affected by a loss of data exchange capability, a mutually agreeable restoration target time. The standard process must also include service-restoration escalation procedures and prioritization criteria.

- Texas RE noticed an inconsistency in language between the standard requirement language and the rationale discussion for Requirement 1 and Requirement 2 which states, "The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to *operating personnel*." Unfortunately, "operating personnel", is not a defined term and the Requirements specifically states "System Operator". Texas RE recommends that the rational language be changed to be consistent with the standard requirements.

- Texas RE is concerned the data retention for R2 is a rolling 30 days while the retention period for R1 is the current calendar year and one previous calendar year with the exception of operator logs and voice recording which shall be retained or a minimum of 90 calendars days. Texas RE inquires as to why there is a difference in the evidence retention period even though there is very little difference in the measures? Texas RE recommends an evidence retention period of a year for both R1 and R2 because there is no basis to distinguish actions to address errors in data inputs (R1) and the analysis of the data inputs (R2) and the longer time frame of a year would give the entity more time to resolve data issues.

- In the Guidelines and Technical Basis documentation there is a statement: "The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel". Texas RE recommends adding: "including the System Operator" or something to that affect. The standard is applicable to the System Operators; the term "operating personnel" is undefined.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group

Answer	Yes

Document Name	

Comment
We suggest to the drafting team to mention more information in the rationale box pertaining to Requirement R1 and its sub-part 1.1 on the expectations for the criteria in reference to evaluating the quality of the real-time data. Additionally, our review group would suggest mentioning the criteria examples spoken of in the drafting team's webinar in the rationale box of this section. The review group's opinion of this is….the criteria examples will give the industry a foundation on how to use various Real-time scenarios to structure their Operational Process or Operational Procedure. In our opinion, Requirement R1 sub-part 1.3 rationale box information (last paragraph) doesn't match the proposed language for that particular section of the Requirement. The Rationale information doesn't clearly state what documentation contains the 'scope of data point information' this proposed language will help clarify. We would ask are you referring to the SAR, or the RTBPTF Report or could it be the FERC Directive. Our review group would suggest mentioning the specific document(s) in the Rationale Section so there will be no misconception on what documentation contains the scope in reference to the data points and how those points should be addressed when providing evidence during an auditing process. As for Requirement R2, we would suggest to the drafting team to include the examples provided in their presentation to the Rationale Section. We feel this information will help give some clarity on what the expectations are for the industry pertaining to Requirement R2. For Requirement R4, we suggest they drafting team include some proposed language that suggests including the 'alarm process monitor that provide modification' into their Operational Process or Operation Procedure. We feel the current language suggests that this process doesn't need to be included in the previously mentioned documentation which could lead to interpretation issues from our perspective.

Likes 0	
Dislikes 0	

Response

Oshani Pathirane - Oshani Pathirane	
Answer	Yes
Document Name	

Comment
Revisions to remove much of the very specific requirements is a good change and Hydro One Networks Inc. supports this. In particular, Hydro One Networks Inc. supports the removal of the list of criteria previously stipulated in Draft 1's R1.1 and R2.1 for evaluating the quality of Real-time data.

Likes 0	
Dislikes 0	

Response

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment

SRP believes the current draft of TOP-010-1 is a significant improvement on the former draft. SRP recommends that in R1 Part 1.3, R2 Part 2.3, and R3 Part3.3 the verbiage should be changed from “Actions to resolve” to “Actions to address”. The TOP and BA may not be able to resolve all quality issues for all the data it receives but they can address all the data with quality issues. This change would retain the responsibility for compliance with the TOP and BA.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE IESO Dominion

Answer	Yes
Document Name	

Comment

We support the draft standard TOP-010-1.

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Kenny - Eversource Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tammy Porter - Tammy Porter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1	
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	
Andrew Pusztai - American Transmission Company, LLC - 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	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the revised Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP	
Answer	No
Document Name	
Comment	
Xcel Energy appreciates the fact that the SDT added some additional time to the Implementation Plan for these standards, however we still feel that the implementation timeline is too short. We continue to propose a 60 month implementation timeline as suggested previously by the MRO Standards Review Forum which states: The implementation plan is too short if entities need to specify, order and deploy new or modified Energy Management Systems (EMS) that can monitor, track, and report real-time data quality and availability in accordance with IRO-018 and TOP-010. Entities should be given an implementation plan with up to 60 months for new EMS software and systems. The key is to allow entities the proper time to assess their tools and complete the right upgrades once. While prompt actions are good, forcing entities to assess, order, and deploy equipment in 12 or 18 months will lead to errors and possibly more risk of serious outages and problems in the short term.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
As the draft standard is currently written, AEP cannot determine the adequacy of the proposed implementation plan. However, if the drafting team were to replace “resolve” with “address” in R1.3 as suggested above, AEP believes the implementation plan would be sufficient.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern believes that the implementation date should be pushed back to at least 24 months following regulatory approval to allow time for the industry to determine the appropriate technology that is sufficient for each entity's operations. We also believe that in order to fully comply with the proposed standard, enough time should be allowed for the industry to update their current procedures and/or to create acceptable procedures, provide training to the appropriate System Operators and allow sufficient time for the entities to determine the technology available that is available and appropriate to support their operations, along with the required functionality.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Since we do not agree with the need for these standards, we do not support the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	
PJM does not support the proposed standards for the reasons noted in 1 and 2 above.	
Likes 1	PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
Dislikes 0	
Response	
Kathleen Goodman - Kathleen Goodman	
Answer	No
Document Name	
Comment	

We do not agree with the need for the two standards, and therefore do not agree with any implementation plans.

Likes 0	
Dislikes 0	

Response

Oshani Pathirane - Oshani Pathirane	
Answer	No
Document Name	
Comment	

Hydro One Networks Inc. proposes that a period of at least 18 months be provided for entities to implement Operating Processes or Operating Processes. Such an effort is onerous and multiple business units and entities would have to align their practices with one another.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

We feel the SDT has made a general assumption that each applicable entity already has the processes, procedures, and infrastructure in place to comply with these requirements. However, we believe entities should have up to 60 months to deploy a new or modified Energy Management System that can monitor, track, and report real-time data quality and availability in accordance with IRO-018 and TOP-010. The key is to allow entities adequate time to assess their tools and complete the right enhancements once. While prompt actions are good practices, forcing entities to assess, order, and deploy equipment within 18 months may lead to unintended consequences.

Likes 0	
Dislikes 0	

Response

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

ATC is in agreement with the Implementation plan for TOP-010-1. IRO-18-1 is not applicable to ATC.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the standardization (and extension of 12 month requirements) such that all requirements become effective on the first day of the first calendar quarter that is 18 months after the date these standards are approved.	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
18 month implementation is better than the previous 12 month implementation. thank you.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE does not agree with the revised Implementation Plan for the proposed standards. Alternatively, Texas RE recommends one year which shoul be sufficient time to implement the new standards since entities are currently responsible for certain real-time monitoring processes and procedures.	

Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Except for those concerns raised in ERCOT's comments above, the proposed Implementation Plan appears reasonable.	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 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	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tammy Porter - Tammy Porter	
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 ISO-NE IESO Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mark Kenny - Eversource Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We believe that not having good data quality and analysis are a medium risk to BES reliability. However, we disagree that the VRFs for these requirements should be classified as Medium, as the Operating Process or Operating Procedure that support both more falls in-line with the criteria of a low risk violation. Our recommendation is further supported with the definition of a Low VRF, as defined within the NERC Violation Risk Factor and Violation Severity Level Justifications document, which states "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." The nonexistence of a related Operating Process or Procedure will have no impact on the state or BES capability.	
Likes 0	
Dislikes 0	
Response	

Oshani Pathirane - Oshani Pathirane	
Answer	No
Document Name	
Comment	
Hydro One Networks Inc. does not support the VSLs, as they are not consistent with the changes made to Draft 2 of the standard. For example, the VSL for R1 assumes that entities would implement one or more of the criteria for evaluating Real-time data quality that have now been removed in Draft 2.	
Likes 0	
Dislikes 0	
Response	

Kathleen Goodman - Kathleen Goodman	
Answer	No
Document Name	
Comment	
We do not agree with the need for the two standards, and therefore do not agree with any proposed VRFs and VSLs.	
Likes 0	

Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	
PJM does not support the proposed standards for the reasons noted in 1 and 2 above.	
Likes 1	PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Since we do not agree with the need for these standards, we do not support the proposed VRFs and VSLs.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Although Southern is encouraged that the SDT has now added some low VRFs/VSLs to the proposed standards, we still maintain that the VRFs and VSLs are too high and should be modified additionally.	
Likes 0	
Dislikes 0	
Response	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	No
Document Name	
Comment	
The VSL for TOP-010-1 Requirement R4 requires the entity to prove the negative for compliance. It is unknown how an entity would prove the alarm process monitor did not fail unless a tertiary monitor was implemented. Tacoma Power does not believe that this is the intent of the standard.	
Likes 0	
Dislikes 0	
Response	

Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

ATC is in agreement with the VRFs/VSLs for TOP-010-1. IRO-18-1 is not applicable to ATC.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
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	
Mark Kenny - Eversource Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
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 ISO-NE IESO Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Tammy Porter	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 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	
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 - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1	
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	
Document Name	

Comment

The VRFs and VSLs forTOP-010-1 should be no greater or less than those of TOP-003-3, TOP-004.

Likes 0	
Dislikes 0	

Response

5. Provide any additional comments for the SDT to consider, if desired.

John Fontenot - Bryan Texas Utilities - 1	
Answer	
Document Name	
Comment	
na	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	
Document Name	
Comment	
na	
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	
None.	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	

Document Name	

Comment

ATC requests a clarification by the SDT in TOP-010-1 on the phrase "affects Real-time Assessments" which is used in sections R1.1.3 and R2.2.3 and the phrase "affecting its Real-time Assessments" in section R3.3.3. Should "affects" be replaced with "effects" or is this correct as written?

Definitions of "affecting"

· Merriam Webster - causing a feeling of sadness or sympathy - evoking a strong emotional response

· Cambridge - causing a strong emotion, especially sadness

· Dictionary.com - moving or exciting the feelings or emotions.

· TheFreeDictionary.com - Inspiring or capable of inspiring strong emotion - moving or stirring the feelings or emotions. - evoking feelings of pity, sympathy, or pathos

Definitions of Effect and Effecting

· Merriam Webster (effect) - change that results when something is done or happens : an event, condition, or state of affairs that is produced by a cause

· Dictionary.com (effect) - something that is produced by an agency or cause; result; consequence - power to produce results; efficacy; force; validity; influence

· Cambridge (effect) - the result of a particular influence; something that happens because of something else:

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

AEP has chosen to vote negative on TOP-010-1, driven by our concerns regarding R1.3, as expressed in our response to Q2.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
On p.12 of the “Guidelines and Technical Basis” document, paragraph 1 defines what is included “Real-time monitoring.” Paragraph 2 goes on to state that there are “functional requirements to perform [Real-time] monitoring… in other standards.” If this is the case, APS recommends the SDT define “Monitoring” as a term in the NERC Glossary as preferable to defining this term in the “Guidelines and Technical Basis” document that is part of the supplemental material in TOP-010.	
Likes 0	
Dislikes 0	
Response	

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
The rational for TOP-010-1 R1 and R2 indicates that the data of concern for those requirements is the same data that was determined in TOP-003-3. The TOP-003-3 standard basically specifies what data is necessary for the Real-time Assessments and TOP-010-1 specifies the quality of that data. SRP recommends combining the two standards so that there is one that addresses what data is necessary and also specifies the quality of that data. Combining the two standards would clarify that the data referred to in TOP-010-1 is the same as the data referred to in TOP-003-1.	
Likes 0	
Dislikes 0	
Response	

Oshani Pathirane - Oshani Pathirane	
Answer	
Document Name	
Comment	

Overall, the second draft has simplified the requirements to an extent. Hydro One Networks Inc. believes that some form of oversight or standardization is required to ensure there is a continuous focus on real time monitoring tools. Data quality measures are appropriate; however, decisions to the degree and method of verification should be left to the discretion of each entity as this will, to an extent, depend on the level of system complexity. A simple system can be tuned to a small error (or convergence) while a complicated system may require a larger allowance.

R1 and R2 – Since the functional requirements, VRFs, and Time Horizons are identical, these two requirements could be combined into one requirement and made applicable to both the Transmission Owner and Balancing Authority.

R2.2 - The wording in R2.2 could be modified to align with that of R1.3, and read, "Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects **Real-time Assessments**.

R4 - The wording could be improved as follows: "*Each Transmission Operator and Balancing Authority shall* ***have alarm process monitoring*** *that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred"*

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment

(1) We request the SDT provide additional rationale on the need to develop new reliability standards, when we feel many current and approved future standards could be enhanced to support the intent of the SAR. Other documentation, such as Reliability Guidelines, could be used to elaborate on specific details and concerns regarding data and analytical qualities.

(2) We thank the SDT for this opportunity to comments on these standards.

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	
Document Name	

Comment

na

Likes 0	
Dislikes 0	

Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	
Document Name	
Comment	
na	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	
Document Name	
Comment	
na	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	
Document Name	
Comment	
na	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name: 2009-02 Real-time Reliability Monitoring and Analysis Capabilities | IRO-018-1 & TOP-010-1

Comment Period Start Date: 12/10/2015

Comment Period End Date: 1/26/2016

Associated Ballots:
2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 AB 2 ST
2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 Non-binding Poll AB 2 NB
2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 AB 2 ST
2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 Non-binding Poll AB 2 NB

There were 38 sets of responses, including comments from approximately 93 different people from approximately 69 companies representing 7 of the Industry Segments as shown in the table on the following pages.

The Project 2009-02 Standards Drafting Team (SDT) appreciates the careful review and constructive feedback from stakeholders. In response to stakeholder comments, the SDT made only clarifying and non-substantive changes to the proposed standards as follows:

IRO-018-1

- Requirement R1 Part 1.3 and Requirement R2 Part 2.3: changed *resolve* to *address* to more clearly align with the SDT's intent for the required actions
- Revised Rationale boxes and Guidelines Section for clarity

TOP-010-1

- Requirement R1 Part 1.3, Requirement R2 Part 2.3, and Requirement R3 Part 3.3: changed *resolve* to *address* to more clearly align with the SDT's intent for the required actions
- Revised Rationale boxes and Guidelines Section for clarity

Questions

1. **Do you agree with the changes made by the SDT to draft standard IRO-018-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.**

2. **Do you agree with the changes made by the SDT to draft standard TOP-010-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.**

3. **Do you agree with the revised Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.**

4. **Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.**

5. **Provide any additional comments for the SDT to consider, if desired.**

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 Information

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	ACES Power Marketing	1	RFC
					Ginger Mercier	ACES Power Marketing	1,3	SERC
					Michael Brytowski	ACES Power Marketing	1,3,5,6	MRO
					John Shaver	ACES Power Marketing	4,5	WECC
					John Shaver	ACES Power Marketing	1	WECC
					Shari Heino	ACES Power Marketing	1,5	TRE
					Bill Hutchison	ACES Power Marketing	1	SERC
					Mark Ringhausen	ACES Power Marketing	3,4	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RFC,SERC	Duke Energy	Doug Hils	Duke Energy	1	RFC
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RFC
MRO		1,2,3,4,5,6	MRO		Joe Depoorter	MRO	3,4,5,6	MRO

	Emily Rousseau			MRO-NERC Standards Review Forum (NSRF)	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.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Robert Schaffeld	Southern Company - Southern Company Services, Inc.	1	SERC

					John Ciza	Southern Company - Southern Company Services, Inc.	6	SERC
					R Scott Moore	Southern Company - Southern Company Services, Inc.	3	SERC
					William Shultz	Southern Company - Southern Company Services, Inc.	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no ISO-NE IESO Dominion	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 Coordinating Council	4	NPCC
					David Ramkalawan	Northeast Power Coordinating Council	4	NPCC
					Glen Smith	Northeast Power Coordinating Council	4	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
					Brian Robinson	Northeast Power	5	NPCC

	Coordinating Council		
Bruce Metruck	Northeast Power Coordinating Council	6	NPCC
Alan Adamson	Northeast Power Coordinating Council	7	NPCC
Michael Jones	Northeast Power Coordinating Council	3	NPCC
Silvia Parada Mitchell	Northeast Power Coordinating Council	4	NPCC
Michael Forte	Northeast Power Coordinating Council	1	NPCC
Sylvain Clermont	Northeast Power Coordinating Council	1	NPCC
Si Truc Phan	Northeast Power Coordinating Council	2	NPCC

					Kelly Silver	Northeast Power Coordinating Council	3	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
					Robert J Pellegrini	Northeast Power Coordinating Council	1	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
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP
					Jason Smith	Southwest Power Pool, Inc. (RTO)	2	SPP

					Jim Nail	Southwest Power Pool, Inc. (RTO)	3,5	SPP
					Mike Kidwell	Southwest Power Pool, Inc. (RTO)	1,3,5	SPP
					Bo Jones	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP
					Allan George	Southwest Power Pool, Inc. (RTO)	1	SPP
					Robert Hirchak	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP

1. Do you agree with the changes made by the SDT to draft standard IRO-018-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

Summary Consideration: The SDT thanks all commenters. The following changes have been made:

- Requirement R1 Part 1.3: changed *resolve* to *address* to more clearly align with the SDT's intent. The SDT recognizes that the applicable entity may not be able to 'resolve' (as in completely remediate) data issues on their own because, for example, another entity may be responsible for providing the data. The revision clarifies that the Reliability Coordinator's Operating Process or Operating Procedure must include "actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments."
- Rationale for Requirement R1 and related information in the Guidelines and Technical Basis Section: Examples of actions to address Real-time data quality issues were added to the Guidelines section and referenced in the Rationale.
- Requirement R2 Part 2.3: changed *resolve* to *address* to more clearly align with the SDT's intent and maintain consistency with Requirement R1.
- Rationale for Requirement R2: Clarified that operating personnel includes System Operators and staff responsible for supporting Real-time operations.
- Reworded lists of examples in the Guidelines and Technical Basis Section.

Responses to comments are provided below.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No

Comment

Southern believes that the criteria in R1.1 should be limited to the RC's ability to monitor and assess the current/expected condition of its RC area within the capabilities of its monitoring tools.

Each RC has the inherent responsibility to protect the integrity of the system in its RC area and contribute to the overall integrity of Interconnection as required by other approved reliability standards. The NERC approved IRO-002-4, IRO-010-2, TOP-003-3 and TOP-004 standards requires the RCs and TOPs to have monitoring tools and capabilities to assess system conditions in its area and to

perform next day and real time reliability assessments to identify/mitigate potential issues that could have an adverse impact on reliability. Moreover, Southern asserts that the capability to maintain an accurate model along with the required telemetry is already being assessed at the certification stage, and that maintenance of such capability does not need to be assessed on an ongoing basis as adequate data quality is required to perform the assessments required by the aforementioned standards. Since the RC is constantly evaluating the quality of data received to ensure it has an accurate state of system conditions to perform real time assessments, through the same processes demonstrated during certification. Southern believes that the reliability goals of maintaining adequate data, tools and situational awareness are accomplished via the IRO-010 and TOP-003-3 NERC reliability standards and to impose this new standard focusing on data quality would only serve as administrative in nature and would not provide any substantial increases in reliability. Given that Southern disagrees with the reliability need for this standard, Southern notes that the detailed requirements (R1.1.1, etc…)regarding assessing data quality, on a point by point basis, was moved to the technical background section of the purposed standard, which is helpful as long as the RSAWs developed doesn't incorporate this "one size fits all" approach for assessing data quality.	
Response. Thank you for your comment. Requirement R1 Part 1.1 applies to Real-time data that the RC has specified are necessary for Real-time monitoring and Real-time Assessments according to IRO-010-2. The SDT believes it is appropriate to have criteria for evaluating the quality of this Real-time data, and not limit the criteria to a subset of the data. However, the proposed requirement specifies that the actions contained in the Operating Process or Operating Procedure are aimed at quality issues affecting Real-time Assessments, which addresses the RCs ability to assess existing and potential system operating conditions. The SDT believes the reliability objectives addressed in this project are closely linked to other Real-time operations requirements and, therefore, they should be maintained on an ongoing basis, in addition to initial certification. Certification ensures the entity has the processes and capabilities to meet the standards, while the requirements themselves ensure the performance is achieved and maintained. The certification process by itself will not ensure these capabilities are maintained. The SDT has provided input on the draft RSAW that is consistent with the changes made to the proposed requirements.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Comment	

We continue to disagree with the need to create Reliability Standards (this and TOP-010-1) to stipulate the requirements for having processes in place to ensure data quality and real-time analysis capability, and adequate alarming system to alert operators of suspicious data or analysis capability. These processes are fundamental to enabling the RC, TOP and BA perform their reliability tasks and meet applicable standard requirements. Data quality, real-time analysis capability and alarming system must be demonstrated during the certification process, and maintained at all times. We continue to urge NERC and the SDT to place these requirements in the Organization Certification Requirements, if they are not already explicitly stipulated.
Response. Thank you for your comment. The proposed requirements are specifically aimed at situational awareness objectives that can impact reliable operations and are not currently addressed in other standards. In particular, the requirements will enhance reliable operations by ensuring operators receive indications of Real-time data quality, have procedures to address Real-time data quality issues that affect Real-time assessments, and are aware when alarming is unavailable. The SDT believes the reliability objectives addressed in this project are closely linked to other Real-time operations requirements and, therefore, they should be maintained on an ongoing basis, in addition to initial certification. Certification ensures the entity has the processes and capabilities to meet the standards, while the requirements themselves ensure the performance is achieved and maintained. The certification process by itself will not ensure these capabilities are maintained.

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C.	
Answer	No
Comment	

PJM does not believe this standard is necessary. RC, BA & TOP entities currently have adequate tools for real-time monitoring and analysis. The existing Standards (i.e., IRO, TOP, & BAL) adequately define what needs to be monitored by each entity without defining the tools. Creating new requirements will not increase the reliability of the BES.

Additionally, some of the new proposed requirements (IRO-018-1 Req. 1, TOP-010-1 Req. 1) state:

Each RC, BA & TOP shall implement an Operating Process to address the *quality* of the Real-time data… the term *quality* is ambiguous and subjective. This term needs to be defined. Similar to Requirement 2, the terms *indications of quality* needs to be defined. If not defined, it could result in varying interpretations throughout the industry.

Lastly, the NERC Operating Reliability Subcommittee (ORS) has drafted a Reliability Guideline, “Loss of Real-Time Reliability Tools Capability / Loss of Equipment Significantly Affecting ICCP Data.” This guideline will help ensure that tools are adequate and if they are degraded for any reason, the potentially impacted entities are aware and can take action if needed. PJM supports the comments submitted by the ISO/RTO Council Standards Review Committee.	
Likes 1	PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
Response. Thank you for your comment. The proposed requirements are specifically aimed at situational awareness objectives that can impact reliable operations and are not currently addressed in other standards. In particular, the requirements will enhance reliable operations by ensuring operators receive indications of Real-time data quality, have procedures to address Real-time data quality issues that affect Real-time assessments, and are aware when alarming is unavailable. The NERC ORS Reliability Guideline does not conflict with the proposed standards, nor does it address the objectives of Project 2009-02. A Reliability Guideline does not ensure adherence in the same way that a Reliability Standard does. To provide clarity to potentially ambiguous terms, the Guidelines and Technical Basis section describes examples of criteria that can be used for evaluating data quality and examples of data quality indicators. In the Operating Process or Operating Procedures, entities must define appropriate criteria, and have the opportunity to establish appropriate criteria based on their systems.	

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2	
Answer	No
Comment	
1. The SRC fails to see the reliability risk that this project is intending to address. The August 14 Blackout as well as the 2011 Southwest Outage have been thoroughly and exhaustively investigated, reported upon, and the root causes mitigated appropriately. Those investigations did not indicate a lack of continent-wide ability to address those root causes – which would be the basis upon a NERC continent-wide reliability standard is needed to address a reliability “gap”. Therefore, pointing to the need for this project based on mitigated, historical events falls short of identifying the reliability risk that this is intended to “fix.” If, for example, WECC continues to have a vested interest in further mitigating the 2011 Southwest Outage through standard development, we suggest this project be migrated into a regional standard for WECC. Lastly, the SRC believes that, absent a Standard specific for tools, a RC, TOP, or BA would,	

in fact, have violations of existing operational Requirements if they do not provide adequate monitoring and tools to their operators (i.e. other "things" would happen). Further, the Requirements as written, "…to address the quality of the Real-time data necessary…" are ambiguous, lack consensus about how to measure, and do not rise to the level of a NERC Standard. 2. This proposed project appears to be well-suited for a guideline document as opposed to a Standard as the proposed requirements address the quality and availability aspects of data and tools for system analysis rather than what's needed to monitor and assess system performance (which are already covered by other standards). As written, the standards appears to intend to stipulate "how" not "what" (*i.e.*, they do not appear to be a results-based standards). The SRC believes that the existing Standards (*i.e.*, IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (*i.e.*, without defining the "how"), which is appropriate. In the alternative, this could be considered a process to be used for Certifying new entities, in line with a methodology developed by the ERO and registered entities for assessing adequacy of tools for addressing the "quality" of real-time data and tools, for assurance that RC, BA and TOPs have the ability to monitor and assess system performance appropriately in accordance with existing, performance-based Standards Requirements. 3. The SRC notes that the tools available to operators have progressed well beyond those available in 2003. If defined tools would have been hardcoded in a standard at that time, it would have limited focus and investment to those things that were in the standard. Further, expanding on our point above, the SRC believes that the "what" regarding tools is more appropriately captured in the certification expectations for BAs, RCs, and TOPs. Additionally, it would be appropriate for Regions to evaluate tools as part of the Registered Entity's Inherent Risk Assessment (IRA). This would include the scope of tools, backups, etc. and would provide an adaptable approach that would encourage continuous improvement. Additionally, the SRC recommends that NERC coordinate with the NATF to encourage inclusion of an ongoing "care and feeding" of tools evaluation and information sharing in their efforts with the provision that they make information on good practices available to the wider NERC community so that non-members can learn from the innovation of others. 4. Finally, to avoid these issues in the future and to support communicating to FERC when a Standard is not needed and another tool is more suitable, the SRC suggests that future SARs be voted on by industry to determine whether they should proceed as a Standards project or another means is a more appropriate method through which to achieve the SAR's objective.
Response. Thank you for your comment.

1. The proposed requirements are specifically aimed at situational awareness objectives that can impact reliable operations and are not currently addressed in other standards. These objectives apply to reliable operations on a continent-wide basis. In particular, the requirements will enhance reliable operations by ensuring operators receive indications of Real-time data quality, have procedures to address Real-time data quality issues that affect Real-time assessments, and are aware when alarming is unavailable.

2. The SDT believes the reliability objectives addressed in this project are closely linked to other Real-time operations requirements and, therefore, they should be maintained on an ongoing basis, in addition to initial certification. Certification ensures the entity has the processes and capabilities to meet the standards, while the requirements themselves ensure the performance is achieved and maintained. The certification process by itself will not ensure these capabilities are maintained.

3. The proposed standard does not specify tools (i.e. does not tell entities 'how'). The suggestion for coordination with NATF is not in scope for Project 2009-02.

4. Stakeholder voting on SARs is not part of the Standards Processes Manual. The Project 2009-02 SAR Drafting Team addressed all comments received during SAR development and the Standards Committee authorized moving forward with Project 2009-02.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy

Answer	No

Comment

Duke Energy suggests changes to the language of the requirements and sub-requirements which would make the standard less vague, and more concise. We recommend the following revisions:

1. R1:

-Modify R1 to state: *"Each Reliability Coordinator shall develop and implement an Operating Process or Operating Procedure to address…"*

We feel that this closes a gap wherein the standard requires an entity to implement a Process or Procedure, but never requires an entity to develop one in the first place.

We believe that R1.1 and R1.2 are similar in nature, and would be better suited as one requirement. We recommend the same revision for R2.1 and R2.2. We suggest the following:

-Combine R1.1 and R1.2 to state: *"Criteria for and display of quality of Real-time data to System Operator."*

R2:

-Modify R2 to state: *"Each Reliability Coordinator shall develop and implement an Operating Process or Operating Procedure to address…"*

We feel that this closes a gap wherein the standard requires an entity to implement a Process or Procedure, but never requires an entity to develop one in the first place.

We believe that R2.1 and R2.2 are similar in nature, and would be better suited as one requirement. We suggest the following:

-Combine R2.1 and R2.2 to state: *"Criteria for and display of quality of Real-time data to System Operator."*

2. Also, we recommend that the requirement be reworded to more closely resemble the rationale. The rationale points out that the RC shall have Processes or Procedures that address issues related to the quality of analysis results used for Real-time Assessments. The language of R2 states that an RC must have Processes or Procedures to address the quality of analysis used in its Real-time Assessments. We feel that adding the word "results" in the requirement decreases possible ambiguity that is currently present in this standard. It is the quality of the results that is paramount, and should be the focus, rather than the quality of the analysis itself. (See out language suggestion after the comment below.)

Next, Duke Energy recommends that R2 should include a provision that an RC should include in their procedure some specification as to what constitutes a "quality issue" (see R2.3) that an RC must take action to resolve. Without having those specifications, it would be difficult to determine what issues necessitate actions and which ones do not. We suggest the following revision to R2:

-Modify R2 to state: *"Each Reliability Coordinator shall develop and implement an Operating Process or Operating Procedure to address the quality analysis results, and include criteria to define levels of material impact, used in its Real-time Assessments."*

3. Lastly, Duke Energy suggests that R3 should be revised to more closely align with the rationale. When reading the rationale, it is clear that the heart of this requirement is having an alarm process monitor capability, and not necessarily the alarm process monitor

itself. We recommend using the language found in the rationale which more clearly state the intent of the requirement. We suggest the following: -Modify R3 to state: *"Each Reliability Coordinator shall have an alarm process monitoring capability that provides notification(s) to its System Operators…"*
Response. Thank you for your comment. 1. The SDT does not believe it is necessary to revise the language of Requirement R1 and R2 to explicitly require development of an Operating Process or Operating Procedure because development is a prerequisite to implementing the Operating Process or Operating Procedure. The SDT does not believe the suggestion to combine the parts in Requirement R1 and Requirement R2 as suggested by the commenter improves the clarity or quality of the proposed standard. 2. The SDT included descriptive details in the rationale for R2 to provide clarity, including examples of analysis and explanation of the requirement objective. The rationale will be retained in the final standard in the Supplemental Material section. Additionally, the SDT believes a specification for 'what constitutes an analysis quality issue' could be addressed in the criteria for evaluating the quality of analysis used in Real-time Assessments required by Part 2.1. Therefore, the suggested changes are not necessary. 3. The SDT does not believe the suggested change adds clarity.

Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC **Nicolas Turcotte - Hydro-Quebec TransEnergie - 1**	
Answer	No
Comment	
The Rational for R3 mentions that the alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.	

What happens when all procedures and processes are followed properly and SCADA system fails because of an IT problem. In another words, RC must not be attributable when SCADA systems fail because of an IT problem. The standard should also consider accountability of the SCADA supplier.

Response. Thank you for your comment. The objective of Requirement R3 is to ensure the System Operator has awareness when failure of Real-time monitoring alarm functions has occurred, regardless of the reason for failure of the alarming functions.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No

Comment

(1) We feel the language within Requirements R1 and R2 are vague and should not require criteria for evaluating data quality and analysis that could be too ambiguous and unenforceable. These requirements need to identify what real-time data and analysis are necessary to perform monitoring and assessment functions, and identify the specifications necessary to maintain reliability. The SDT should clarify the meaning of “quality,” and incorporate this explanation in the standard’s Guidelines and Technical Basis or Rationale sections. Without a minimum criteria specified, we feel this does not provide enough information to make an objective determination for an auditor. Furthermore, we suggest adding references to Part 1.3 and Part 2.3 that mitigation actions should be initiated within 30 minutes. We feel these references align the failure to implement actions with other mitigation actions required.

(2) Requirement R3 expects the RC to have evidence that it has an alarm process monitor that provides failure notifications to System Operators. We feel this language is redundant with many requirements of Reliability Standard IRO-002-2. For instance, Requirement R4 of IRO-002-2 states the RC “shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas.” Moreover, Requirement R7 of IRO-002-2 states “Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area.” While requirements R1 and R2 of the proposed standard, IRO-018-1, are concerned with quality expectations of data and analysis, respectively, Requirement R3 identifies a tool or application that the RC must own and operate. In order to meet the various requirements of IRO-002-2, the RC would already be required to own and operate such applications. Hence, we recommend the SDT remove requirement R3 of the proposed standard.

(3) We continue to have concerns that these requirements only focus on System Operators. We feel that an auditor may not interpret the standard to allow other employees, such as EMS Engineers, to mitigate data or analytical errors. According to the NERC Glossary

Term, a System Operator is one “who operates or directs the operation of the Bulk Electric System (BES) in Real-time.” We recommend the SDT clarify that these requirements can apply to other employees.
Response. Thank you for your comments. 1. The proposed standard does not require the RC to determine what data is required for Real-time monitoring or Real-time Assessments because the RC is obligated to do so in IRO-010-2. To provide clarity to potentially ambiguous terms, the Guidelines and Technical Basis section describes examples of criteria that can be used for evaluating data quality and examples of data quality indicators. The SDT does not believe minimum ‘one size fits all’ criteria for data quality or timeframe for addressing data quality issues can be established as part of a continent-wide standard requirement. The requirement provides entities with the flexibility to establish appropriate timeframes for addressing data quality issues based on reliability needs and system considerations. 2. The SDT does not agree that requirements in IRO-002-2 require entities to own or operate an application to provide operator notification when alarming functions have failed. Proposed Requirement R3 clearly establishes requirements to provide operator notification when alarming functions have failed and addresses Recommendation S7 from the Real-time Tools Best Practices Task Force report. 3. The SDT has revised the Rationale for Requirement R2 to clarify that operating personnel includes System Operators or other personnel responsible for supporting Real-time operations. Requirements specifically include System Operators where appropriate for reliability. Entities have flexibility to expand notification and actions to other operating personnel and support staff in their Operating Process or Operating Procedure.

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1	
Answer	No
Comment	
See comments for Q2.	
Response. See response in next section.	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	Unofficial_Comment_Form_2009-02_121015_ERCOT draft_ssolis_eha_nb.docx
Comment	

Comments: ERCOT continues to be concerned that the proposed standard is too prescriptive and goes beyond the associated FERC directive regarding a requirement addressing “capabilities.” In particular, these standards were developed to address operator awareness of tool or other outages that could impact real-time monitoring.

Further, several of the requirements involve many more entities beyond the Reliability Coordinators and, absent a requirement for coordination, participation, and action in response to the Reliability Coordinator’s identification of an issue, the proposed standard will not achieve its intended objective as written. This is extremely challenging (R1.3) because the majority of issues related to poor data quality or invalid analysis tool solutions can only be resolved by parties outside of the Reliability Coordinator (e.g facility owners, telecom companies, etc.)

Additionally, real-time data and monitoring capabilities are critical to the certification of a Reliability Coordinator and are not “dynamic.” Because such “capabilities” are complex, require coordination and inputs from other entities, and are key to the continued performance of a Reliability Coordinator’s duties, they are not subject to frequent change and therefore likely do not need continued monitoring and assessment.

Finally, several other reliability standards and associated requirements are contingent upon the availability of real-time tools and data, and these other standards and requirements are subject to the compliance monitoring and enforcement program. ERCOT would recommend that requirements addressing capabilities be utilized as part of certification review and not as a reliability standard subject to the compliance monitoring and enforcement program.

Should NERC continue this project, however, ERCOT recommends the following language adjustments to Requirement R1.3. No matter what the SDT *intends* the language to mean, this requirement language may still be read to mean the RC’s Operating Process or Operating Procedure should be written to actively resolve data quality issues even though the ability to resolve data issues may lie with another party. Accordingly, ERCOT recommends:

R1.3 current language: "Actions to resolve Real-time data quality issues with the entity(ies) responsible for proving the data when data quality affects Real-time Assessments." R1.3 ERCOT suggested language: "Actions to notify the entity(ies) responsible for providing data of any Real-time data quality issue affecting Real-time Assessments." This language aligns with the objective communicated by the SDT, aligns with what is in practice today, aligns with the SDT concept that IRO-010 and TOP-005/003 require data providers to address data quality issues, and is within the capability of the Reliability Coordinator to perform. This language is also consistent with the numerous examples within the NERC Reliability Standards where an entity is required to notify other entities that are responsible for or have an obligation to take actions where the notifying entity cannot or does not perform the reliability task.
Response. Thank you for your comments. The SDT recognizes that resolving data quality issues may require action from entities in addition to the applicable RC. By requiring the RC to have an Operating Procedure or Operating Process that includes steps to address data quality issues affecting its Real-time Assessment, the proposed standard provides flexibility for the RC to accomplish the reliability objective in a manner that accounts for authorities and agreements that are in place. For example, IRO-010-2 Requirement R3 Part 3.2 specifies that entities receiving a data specification shall satisfy their obligations in the data specification using a mutually-agreeable process for resolving data conflicts. To clarify this, the SDT has included examples of actions to address data quality issues in the Guidelines section for Requirement R1. The SDT believes the reliability objectives addressed in this project are closely linked to other Real-time operations requirements and, therefore, they should be maintained on an ongoing basis, in addition to initial certification. Certification ensures the entity has the processes and capabilities to meet the standards, while the requirements themselves ensure the performance is achieved and maintained. The certification process by itself will not ensure these capabilities are maintained.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE IESO Dominion	
Answer	Yes
Comment	
We support the draft standard IRO-018-1.	

R2 2.3 Instead of "Action to resolve analysis quality issues affecting its Real-time Assessments", suggest change the language to "Action to resolve quality analysis issues affecting its Real-time Assessments."	
Response. Thank you for your comments. The SDT carefully considered the suggested change and does not believe it provides additional clarity.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group	
Answer	Yes
Comment	
1. We suggest to the drafting team to mention more information in the rationale box pertaining to Requirement R1 and its sub-part 1.1 on the expectations for the criteria in reference to evaluating the quality of the real-time data. Additionally, our review group would suggest mentioning the criteria examples spoken of in the drafting team's webinar in this section of the rationale box. The review group's opinion of this is….the criteria examples will give the industry a foundation on how to use various Real-time scenarios to structure their Operational Process and/or Operational Procedure. In our opinion, Requirement R1 sub-part 1.3 rationale box information (last paragraph) doesn't match the proposed language for that particular section of the Requirement. The Rationale information doesn't clearly state what documentation contains the 'scope of data point information' this proposed language will help clarify. We would ask are you referring to the SAR, or the RTBPTF Report or could it be the FERC Directive? Our review group would also suggest mentioning the specific document(s) in the rationale section so there will be no misconception on what documentation contains the scope in reference to the data points and how those points should be addressed when providing evidence during an auditing process. 2. As for Requirement R2, we would suggest to the drafting team to include the examples provided in their presentation to the rationale section. We feel this information will help give some clarity on what the expectations are for the industry pertaining to Requirement R2. For Requirement R3, we suggest that the drafting team include some proposed language that suggests including the 'alarm process monitor that provide modification' into their Operational Process or Operation Procedure. We feel the current language suggests that this process doesn't need to be included in the previously mentioned documentation which could lead to interpretation issues from our perspective.	

Response. Thank you for your comment.

1. The example criteria are included in the Guidelines and Technical Basis section. Requirement R1 Part 1.3 requires RCs to include steps to address data quality issues affecting Real-time Assessments. This is a more limited scope than all of the data points being monitored by the RC. If a data point does not affect Real-time Assessment, then no action is required by Requirement R1 Part 1.3.

2. The examples of types of analysis used in Real-time assessments and quality criteria are included in the Guidelines and Technical Basis section.

3. The SDT does not intend to require RCs to address alarm process monitoring in an Operating Procedure or Operating Process that is implemented to meet requirements of the proposed standard.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Comment	

In general, Texas RE agrees with the changes made by the SDT to draft standard IRO-018-1. However, Texas RE provides the following comments or suggestions to the proposed standard:

- Texas RE suggests the SDT consider explicitly stating real-time monitoring in addition to real-time assessments in R1.3. For example, "Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time monitoring and Real-time Assessments. In addition, Texas RE would like to highlight that Texas RE is concerned there is no definitive timeframe provided associated with the actions to resolve issues which may lead to a reliability gap due to a myriad of approaches taken by registered entities. Texas RE supports the RTBPTF recommendations related to real-time monitoring. Specifically, for telemetry data systems:

1) Increase the minimum update frequency for operational reliability data from once every 10 minutes to once every 10 seconds.16

2) Standardize the procedures, processes, and rules governing key data exchange issues.17

3) Institute a requirement for data availability from ICCP or other equivalent systems, based on the ratio of "good" data received (as defined by data quality codes) to total data received. The ratio must exceed 99 percent for 99 percent of the sampled periods during a calendar month. In addition, the ratio must not be less than 99 percent for any 30 consecutive minutes.

4) Establish minimum response times for restoration of data exchange between control centers following the loss of a data link or other problems within the source system. As part of this requirement, a trouble-resolution process standard must be developed that requires all entities responsible for management and maintenance of ICCP or equivalent systems to identify, with data recipients that could be affected by a loss of data exchange capability, a mutually agreeable restoration target time. The standard process must also include service-restoration escalation procedures and prioritization criteria.

- Texas RE noticed an inconsistency in language between the standard requirement language and the rationale discussion for Requirement 1 and Requirement 2 which states, "The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to *operating personnel*." Unfortunately, "operating personnel", is not a defined term and the Requirements specifically states "System Operator". Texas RE recommends that the rational language be changed to be consistent with the standard requirements.
- Texas RE is concerned the data retention for R2 is a rolling 30 days while the retention period for R1 is the current calendar year and one previous calendar year with the exception of operator logs and voice recording which shall be retained or a minimum of 90 calendars days. Texas RE inquires as to why there is a difference in the evidence retention period even though there is very little difference in the measures? Texas RE recommends an evidence retention period of a year for both R1 and R2 because there is no basis to distinguish actions to address errors in data inputs (R1) and the analysis of the data inputs (R2) and the longer time frame of a year would give the entity more time to resolve data issues.

Response. Thank you for your comments.

1. The SDT does not agree that all data quality issues affecting Real-time monitoring need to be addressed in the Operating Procedure or Operating Process specified by Requirement R1. The scope of Requirement R1 Part 1.3 addresses data quality issues that could impact reliability by affecting Real-time Assessments. The SDT does not believe adding a prescriptive time requirement to Part 1.3 is feasible or necessary for reliability. Entities should exercise judgment to address data quality issues in appropriate timeframes to satisfy obligations for the performance of Real-time Assessments.

2. The SDT has revised the Rationale for Requirement R2 to clarify that operating personnel includes System Operators or other personnel responsible for supporting Real-time operations. Requirements specifically include System Operators where appropriate for reliability. Entities have flexibility to expand notification and actions to other operating personnel and support staff in their Operating Process or Operating Procedure. 3. The evidence retention period for Requirement R2 is aligned with the evidence retention period for Real-time Assessments contained in IRO-008-2 Requirement R4. The SDT's intent is to maintain consistency within the TOP and IRO family of standards.	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP	
Answer	Yes
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Jared Shakespeare - Peak Reliability - 1	
Answer	Yes

Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Mark Kenny - Eversource Energy - 3	
Answer	Yes
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Comment	
Not applicable to BPA.	
Response.	

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Comment

IRO-018-1 is not applicable to Hydro One. However, Hydro One Networks Inc. would like to point out that R1.2 should specify, that the RC’s Operating Process or Operating Procedure which is to include actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data, should include a mutually agreed upon schedule and actions.

Response. Thank you for your comments. The proposed requirement provides flexibility for the RC's Operating Process or Operating Procedure to include whatever actions are appropriate to address data quality issues. The actions and schedule could be based on the RCs authority or agreements with other entities.

2. Do you agree with the changes made by the SDT to draft standard TOP-010-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

Summary Consideration: The SDT thanks all commenters. The following changes have been made:

- Requirement R1 Part 1.3: changed *resolve* to *address* to more clearly align with the SDT's intent. The SDT recognizes that the applicable entity may not be able to ‘resolve’ (as in completely remediate) data issues on their own because, for example, another entity may be responsible for providing the data. The revision clarifies that the Transmission Operator's Operating Process or Operating Procedure must include "actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments."
- Requirement R2 Part 2.3: changed *resolve* to *address* to more clearly align with the SDT's intent. The SDT recognizes that the applicable entity may not be able to ‘resolve’ (as in completely remediate) data issues on their own because, for example, another entity may be responsible for providing the data. The revision clarifies that the Balancing Authority's Operating Process or Operating Procedure must include "actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions."

- Rationale for Requirements R1 and R2 and related information in the Guidelines and Technical Basis Section: Examples of actions to address Real-time data quality issues were added to the Guidelines section and referenced in the Rationale.
- Requirement R3 Part 3.3: changed *resolve* to *address* to more clearly align with the SDT's intent and maintain consistency with Requirement R1.
- Rationale for Requirement R3: Clarified that operating personnel includes System Operators and staff responsible for supporting Real-time operations.
- Reworded lists of examples in the Guidelines and Technical Basis Section.

Responses to comments are provided below.

Scott McGough - Georgia System Operations Corporation - 3

Answer	No

Comment

The language is too ambiguous.

Response. Thank you for your comment. The SDT has addressed stakeholder comments and suggestions to enhance clarity.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	No

Comment

Comments: For purposes of this comment, ERCOT incorporates all of its above comments regarding IRO-018-1. As with R1.3 in IRO-018-1, ERCOT is concerned that certain language in TOP-010-1 could be read to suggest that the RC must resolve Real-time data quality issues, when in fact the ability to resolve data issues may lie with another party. Consistent with its suggested revisions to R1.3 in IRO-018-1, ERCOT recommends the following changes to R1.3 and R2.3 in TOP-010-1:

R1.3 current language: "Actions to resolve Real-time data quality issues with the entity(ies) responsible for proving the data when data quality affects Real-time Assessments."

R1.3 ERCOT suggested language: "Actions to notify the entity(ies) responsible for providing data of any Real-time data quality issue affecting Real-time Assessments." And R2.3 current language: "Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions." R2.3 ERCOT suggested language: "Actions to notify the entity(ies) responsible for providing data of any Real-time data quality issue affectings its analysis functions."
Response. Thank you for your comments. Response is provided in the previous section.

John Brockhan - CenterPoint Energy Houston Electric, LLC - 1	
Answer	No
Comment	
CenterPoint Energy understands recommendations for the scope of this project originated from the 2011 Southwest Outage Report as well as FERC directives in Order 693, however with the vast improvement in technologies involved with monitoring and analysis capabilities over the last 10 years, these recommendations as well as the scope of this project is potentially outdated. CenterPoint Energy is concerned that compliance with Requirements in TOP-010-1 could represent a documentation burden without providing a measureable benefit to reliability. The main focus of the directives and recommendations referenced above appear to be more related to real-time analysis tools rather than quality of data. CenterPoint Energy believes and feels the industry would benefit more from, reducing the scope of the Standard to those data quality issues that negatively impact real-time analysis and assessments. CenterPoint Energy recommends the SDT delete Parts 1.1, 1.2, 2.1, and 2.2.	
Response. Thank you for your comments. Requirements R1 and R2, Parts 1.1, 1.2, 2.1, and 2.2 are included for operator situational awareness in line with the Project 2009-02 objectives. The SDT believes these provisions are important for complete and effective Operating Processes or Operating Procedures addressing Real-time monitoring and analysis capabilities.	
Nicolas Turcotte - Hydro-Quebec TransEnergie - 1	

Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC	
Answer	No
Comment	

See comments from question 1 but replacing RC for TOP and BA

What happen when all procedures and processes are followed properly and SCADA system fails because of an IT problem? In another words, BA or TOP must not be attributable when SCADA systems fail because of an IT problem. The standard should also consider accountability of the SCADA supplier

Response. Thank you for your comments. Response is provided in the previous section.

Daniel Mason - City and County of San Francisco - 1,5	
Answer	No
Comment	

The draft version of Requirement R4. reads as follows:

Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

We believe greater clarity could be brought to this requirement by modifying two awkward terms, "alarm process monitor" and "monitoring alarm processor", as follows:

Each Transmission Operator and Balancing Authority shall monitor its Real-time monitioring alarm system and provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm system has occurred.

Response. Thank you for your comments. Requirement R4 is aimed at ensuring TOPs and BAs have an alarm process monitoring capability. The SDT does not believe the commenter's suggested change would clearly achieve this objective.

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1	
Answer	No
Comment	

The changes made to R1 are helpful in clarifying the scope of data included in this requirement however the term "quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments" would still imply all data specified per TOP-003 as all data specified will be the data used in Real time Assessment and therefore will require TOP to take action on any failed data point. Also the term real time monitoring is not a defined term and should be removed.

In addition to the above comments, ITC Holdings agrees with the comments submitted by the SPP Standards Review Group. A copy of SPP's comments are provided below.

We suggest to the drafting team to mention more information in the rationale box pertaining to Requirement R1 and its sub-part 1.1 on the expectations for the criteria in reference to evaluating the quality of the real-time data. Additionally, our review group would suggest mentioning the criteria examples spoken of in the drafting team's webinar in the rationale box of this section. The review group's opinion of this is….the criteria examples will give the industry a foundation on how to use various Real-time scenarios to structure their Operational Process or Operational Procedure.

In our opinion, Requirement R1 sub-part 1.3 rationale box information (last paragraph) doesn't match the proposed language for that particular section of the Requirement. The Rationale information doesn't clearly state what documentation contains the 'scope of data point information' this proposed language will help clarify. We would ask are you referring to the SAR, or the RTBPTF Report or could it be the FERC Directive. Our review group would suggest mentioning the specific document(s) in the Rationale Section so there will be no miss conception on what documentation contains the scope in reference to the data points and how those points should be addressed when providing evidence during an auditing process.

As for Requirement R2, we would suggest to the drafting team to include the examples provide in their presentation to the Rationale Section. We feel this information will help give some clarity on what the expectations are for the industry pertaining to Requirement R2.

For Requirement R4, we would suggest they drafting team would include some proposed language that suggests including the 'alarm process monitor that provide modification' into their Operational Process or Operation Procedure. We feel the current language

suggests that this process doesn't need to be included in the previously mentioned documentation which could lead to interpretation issues from our perspective.	
Response. Thank you for your comments. The SDT does not agree that all data specified in TOP-003-3 is used for Real-time Assessments, and consequently views proposed Requirement R1 Part 1.3 to be appropriately scoped to address the set of data that impacts Real-time Assessments. Also see response to SPP.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Comment	

(1) We feel the language within Requirements R1 and R3 are vague and should not require criteria for evaluating data quality and analysis that could be too ambiguous and unenforceable. These requirements need to identify what real-time data and analysis are necessary to perform monitoring and assessment functions, and identify the specifications necessary to maintain reliability. The SDT should clarify the meaning of "quality," and incorporate this explanation in the standard's Guidelines and Technical Basis or Rationale sections. Without a minimum criteria specified, we feel this does not provide enough information to make an objective determination for an auditor. Furthermore, we suggest adding references to Part 1.3 and Part 3.3 that mitigation actions should be initiated within 30 minutes. We feel these references align the failure to implement actions with other mitigation actions required in other reliability standards.

(2) We understand the SDT interprets the intent of requirement R4 of the industry-approved standard, BAL-005-1, to pertain to only the data necessary to calculate Reportable ACE. Moreover, the SDT feels that the proposed Requirement R2 does not create double jeopardy with BAL-005-1, and that Requirement R2 is necessary to account for other data monitored by a BA. We disagree and feel the SDT should remove this redundant requirement or identify this other data in the rationale of this requirement.

(3) The intent of Requirement R4 requires a TOP or BA to monitor the availability of its real-time monitoring alarm processor. We feel this requirement is unnecessary, as similar actions are accomplished in order to maintain compliance with other reliability requirements. For instance, Requirement R5 of TOP-006-3 states "each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating

conditions...” In order to maintain compliance with this requirement, a registered entity is obligated to notify its own personnel when they are unable to use such monitoring equipment. We recommend the SDT remove Requirement R4 from the proposed standard. (4) We continue to have concerns that these requirements only focus on System Operators. We feel that an auditor may not interpret the standard to allow other employees, such as EMS Engineers, to mitigate data or analytical errors. According to the NERC Glossary Term, a System Operator is one “who operates or directs the operation of the Bulk Electric System (BES) in Real-time.” We recommend the SDT clarify that these requirements can apply to other employees.	
Response. Thank you for your comments. 1. See response 1 to ACES comments in previous section. The TOP is obligated to determine what data is required for Real-time monitoring and Real-time Assessments by TOP-003-3 Operational Reliability Data. 2. Requirement R2 addresses the BA analysis functions and Real-time monitoring obligations for maintaining Demand and resource balance as described in the NERC Functional Model and TOP-001-3. Requirement R2 applies to data specified by the BA per TOP-003-3 Requirement R2. 3. TOP-006-3 is approved for retirement. The SDT does not agree that other Reliability Standards address the objective of proposed TOP-010-1 Requirement R4. 4. The SDT has revised the Rationale for Requirement R3 to clarify that operating personnel includes System Operators or other personnel responsible for supporting Real-time operations. Requirements specifically include System Operators where appropriate for reliability. Entities have flexibility to expand notification and actions to other operating personnel and support staff in their Operating Process or Operating Procedure.	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Comment	
How is quality defined? This is too ambiguous as written and internal discussions resulted in multiple opinions. Quality needs to be better defined within the requirement.	

Response. Thank you for your comments. To provide clarity to potentially ambiguous terms, the Guidelines and Technical Basis section describes examples of criteria that can be used for evaluating data quality and examples of data quality indicators. The SDT does not believe minimum 'one size fits all' definition of quality can be established as part of a continent-wide standard requirement.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy	
Answer	No
Comment	
Duke Energy recommends the same changes to the language in TOP-010-1 that it does for IRO-018-1.	
Response. Thank you for your comments. See response in previous section.	
Jamison Cawley - Nebraska Public Power District - 1 **Don Schmidt**	
Answer	No
Comment	
We do not believe the issues addressed by the FERC directive rise to the level of requiring a reliability standard. The intent of the directive and the resulting actions to be taken by the various entities would be better served by an official Guideline rather than a generic standard. Forcing this into a Standard result in varied interpretations and approachs to "quality" and "adequacy" that do not enhance reliability of the BES. We believe the requirements in general could be improved to be more results based. As written, they largely will only result in identifying deficiencies after the fact when doing event analysis. An entity may have a process or procedure as required, but they could miss a piece of data or fail to identify fully the impact a quality issue may have upon their situational awareness. Simply having the process does not result in increased reliability. Most entities already have a process in place to alarm or indicate data quality as needed to maintain reliability. Entities are already required to operate reliably, within SOLs and IROLs, etc. The creation of this standard as written would serve only to document that	

process and put it under auditable enforcement – with no discernible impact to maintaining reliability. In order to make this standard truly results based, there needs to be some identification of the quality level, or data quality thresholds that must be maintained in order for reliability to be maintained. Then that level (or quality of the data measurements) must be maintained per the standard.

We suggest that there needs to be more direction given by the Standard in a few areas. One is that the applicable entity should be determining a data range, time periods, number of manually entered values, etc. that can degrade analysis to the point reliability is threatened (R1.1.1-R1.1.4).

We find it problematic when an entity may not "own" the data and is simply receiving a quality flag from a sender. An entity may not receive an accurate quality flag or the quality flag is corrupted in translation over ICCP. Also, there is no requirement that the measurement devices even be of a particular accuracy. For example the quality threshold may be more narrow than the accuracy of the device.

Response. Thank you for your comments. The SDT believes the Operating Processes or Operating Procedures required by the proposed standard should be developed to support Real-time operations, not just event analysis functions. Because entities have different systems, tools, and capabilities, the proposed standard provides needed flexibility rather than imposing prescriptive requirements that would not be effective in a continent-wide standard. Determining data range, time periods, or number of manually entered values, as suggested, could be part of the criteria an entity uses in the Operating Process or Operating Procedure. An objective of an entity's Operating Procedure or Operating Process should be to establish criteria that will identify potentially bad ICCP data points that affect Real-time Assessments so that actions can be taken by entities responsible for providing the data. Measurement device accuracy requirements necessary for reliable operations will vary and therefore are not addressed in the proposed continent-wide standard.

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2

Answer	No

Comment

same comments as under Q1 above.

Response. Thank you for your comments. See response provided in previous section.

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	No
Comment	

PJM does not believe this standard is necessary. RC, BA & TOP entities currently have adequate tools for real-time monitoring and analysis. The existing Standards (i.e., IRO, TOP, & BAL) adequately define what needs to be monitored by each entity without defining the tools. Creating new requirements will not increase the reliability of the BES.

Additionally, some of the new proposed requirements (IRO-018-1 Req. 1, TOP-010-1 Req. 1) state:

Each RC, BA &TOP shall implement an Operating Process to address the *quality* of the Real-time data… the term *quality* is ambiguous and subjective. This term needs to be defined. Similar to Requirement 2, the terms *indications of quality* needs to be defined. If not defined, it could result in varying interpretations throughout the industry.

Lastly, the NERC Operating Reliability Subcommittee (ORS) has drafted a Reliability Guideline, "Loss of Real-Time Reliability Tools Capability / Loss of Equipment Significantly Affecting ICCP Data." This guideline will help ensure that tools are adequate and if they are degraded for any reason, the potentially impacted entities are aware and can take action if needed.

PJM supports the comments submitted by the ISO/RTO Council Standards Review Committee.

Likes 1	PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
Response. Thank you for your comments. Response provided in previous section.	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Comment	

Same comment as for IRO-018-1. Please see our comment under Q1, above.

Response. Thank you for your comments. Response provided in previous section.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No

Comment

Southern believes that the criteria in R1.1 should be limited to the BA/TOP's ability to monitor and assess the current/expected condition of its RC area within the capabilities of its monitoring tools.

Each BA/TOP has the inherent responsibility to protect the integrity of the system in its BA/TOP area and contribute to the overall integrity of Interconnection as required by other approved reliability standards. The NERC approved TOP-003-3 and TOP-004 standards requires BAs/TOPs to have monitoring tools and capabilities to assess system conditions in its area and to perform next day and real time reliability assessments to identify/mitigate potential issues that could have an adverse impact on reliability. Moreover, Southern asserts that the capability to maintain an accurate model along with the required telemetry is already being assessed at the certification stage, and that maintenance of such capability does not need to be assessed on an ongoing basis as adequate data quality is required to perform the assessments required by the aforementioned standards. In addition, there are already NERC approved standards such as TOP-002-2 that currently require the BA/TOP to maintain accurate computer models for analyzing system operations.

Since the TOP is constantly evaluating the quality of data received to ensure it has an accurate state of system conditions to perform real time assessments, through the same processes demonstrated during certification, Southern believes that the reliability goals of maintaining adequate data, tools and situational awareness are accomplished via the IRO-010 and TOP-003-3 NERC reliability standards and to impose this new standard focusing on data quality would only serve as administrative in nature and would not provide any substantial increases in reliability.

Given that Southern disagrees with the reliability need for this standard, Southern notes that the detailed requirements (R1.1.1, etc…)regarding assessing data quality, on a point by point basis, was moved to the technical background section of the purposed standard, which is helpful as long as the RSAWs developed doesn't incorporate reapply this "one size fits all" approach for assessing data quality.

Response. Thank you for your comment.

Requirement R1 Part 1.1 and R2 Part 2.1 apply to Real-time data that the TOP and BA have specified are necessary for Real-time monitoring and Real-time Assessments according to TOP-003-3. The SDT believes it is appropriate to have criteria for evaluating the quality of this Real-time data, and not limit the criteria to a subset of the data. However, the proposed requirement specifies that the actions contained in the Operating Process or Operating Procedure are aimed at data quality issues affecting Real-time Assessments, which addresses the TOP and BA's ability to assess existing and potential system operating conditions. The SDT believes the reliability objectives addressed in this project are closely linked to other Real-time operations requirements and, therefore, they should be maintained on an ongoing basis, in addition to initial certification. Certification ensures the entity has the processes and capabilities to meet the standards, while the requirements themselves ensure the performance is achieved and maintained. The Certification process by itself will not ensure these capabilities are maintained.	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	No
Comment	
Requirements R1 and R2 apply to monitoring system conditions. Therefore Tacoma Power believes both requirements should be included in TOP-006-2. Additionally Tacoma Power believes Requirement R4 is unnecessarily redundant, providing no foreseeable improvement to reliable operation of the bulk electric system.	
Response. Thank you for your comments. TOP-006-2 has been approved for retirement and requirements for Real-time monitoring are addressed in other standards including TOP-001-3 and IRO-008-2. The SDT determined the development of new proposed reliability standards was appropriate for accomplishing the objectives of Project 2009-02. Requirement R4 addresses recommendations from the Real-time Tools Best Practices Task Force 2008 report and lessons learned from the 2003 Blackout.	
Thomas Foltz - AEP - 5	
Answer	No
Comment	

While AEP agrees with the overall approach and intent of R1, we believe that sub-Requirement R1.3 goes beyond the scope of its parent Requirement. While R1 focuses on ***addressing*** the quality of Real-time data, R1.3 requires the Transmission Operator's Operating Process or Procedure to include actions to ***"resolve"*** Real-time data quality issues when data quality affects Real-time Assessments. This is especially concerning when the "entity(ies) responsible for providing the data" are external. Neither the Transmission Operator, nor its Operating Procedure, is able to resolve data issues involving points over which they have no direct control. The entity would have control over their own analysis quality (R3), but again, not the quality of external data. In the webinar held on January 11, the drafting team inferred a different interpretation of R1.3 depending on whether or not the data is externally provided. The drafting team seemed to be saying "no, you don't need to resolve data issues for points you do not own, but you still need to document actions to resolve those data issues", etc. That seems to infer that "actions to resolve" might, in some cases, simply be *informing* the data owner of the issue rather than *remediating* issues involving the external data. While the drafting team might interpret R1.3 in this manner, there is no assurance that an auditor would have that same viewpoint. And if that is indeed the drafting team's interpretation , R1.3 does not articulate that. In this same webinar, a drafting team member eventually used the phrase "address the quality" in regards to externally provided data. AEP believes the word "address" is much more appropriate for R1.3 than "resolve", and using it would allow R1.3 to align with R1 (which already uses the word "address"). As a result, we recommend that the word "resolve" in R1.3 be replaced by "address", so that it states "Actions necessary to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments."
Response. Thank you for your comments. The SDT has changed *resolve* to *address*, and added clarifying details to the Guidelines section.

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	AZPS-Comments_Question-2_Project-2009-02_Draft-2.docx
Comment	
Where the current requirements, R1.3, R2.3, and R3.3, state that there need to be "actions to resolve…quality issues affecting Real-Time Assessments," APS recommends this language be modified to only when "quality issues **adversely** affecting Real-Time Assessments."	

APS does not agree with the use of the word "resolve" in requirements, R1.3, R2.3, and R3.3, as there will be times when the quality issues arise from data that is being provided by an external resource, thereby limiting an entities' ability to "resolve" the issue. APS recommends replacing the word "resolve" with "**address**."

In addition, APS appreciates the time and effort spent by the SDT to provide the rationale for Requirements and the "Guidelines and Technical Basis" as these sections provide insight as to what is compliant. That said, APS believes the content in these sections needs to be limited to an explanation of what is in the requirements and not expand the scope of the requirements by using words such as "must" or "shall."

There are multiple instances where the current rationale for Requirements and the "Guidelines and Technical Basis" document add requirements to those contained in the base standard via the use of ***definitive examples*** that are then subsequently incorporated into the proposed RSAW for TOP-010. Specific examples are provided under the Analysis of "Guidelines and Technical Basis" Supplemental Material below.

APS recommends the SDT review each example and consider either rewriting the standard to include the additional provisions introduced in the supplemental material into the requirement or rewrite the rationale/"Guidelines and Technical Basis" as illustrative (versus definitive) examples.

Analysis of "Guidelines and Technical Basis" Supplemental Material

	Existing Language	APS Proposed Language
Introduction	"Real-time monitoring ***includes*** the following activities performed in Real-time:…"	"Real-time monitoring ***may include*** activities performed in Real-time such as:…"
Requirement, R1	The criteria support identification of ***applicable*** data quality issues, such as:" (paragraph 2)	"The criteria support identification of data quality issues, ***which may include items*** such as:"

	"The Operating Process or Operating Procedure must clearly identify to ***operating personnel how to determine the data that affects the quality*** of the Real-time Assessment so that effective actions can be taken to resolve data quality issues ***in an appropriate timeframe***" (paragraph 5) The existing language changes the scope of R1.2 and R1.3 in three ways: 1) Changes "System Operator" to "operating personnel" 2) Shifts the burden of determining the quality of data to operating personnel (as opposed to providing quality indicators to the System Operator) 3) Introduces a new requirement to resolve issues in an appropriate timeframe	"The Operating Process or Operating Procedure must describe ***how the quality of Real-time data is indicated to System Operators*** so that actions can be taken to resolve Real-time data quality issues **adversely** affecting the quality of Real-time Assessments."
R2	Same as comments to R1	Same as comments to R1
Requirement, R3	"Examples of the types of analysis used in Real-time Assessments ***include***, as applicable, …" (paragraph 1)	"Examples of the types of analysis used in Real-time Assessments ***may include***, as applicable, …" (paragraph 1)
	"The entity ***must use appropriate*** quality criteria based on the analysis capabilities used to perform Real-time Assessments, ***such as***:…" (paragraph 2)	"***Examples of the type*** of criteria used to evaluate the quality of the analysis used in Real-time Assessments ***may include*** items such as:"
	"The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessments will be shown to operating personnel." (paragraph 3)	To clarify: "The Operating Process or Operating Procedure must describe how the quality of analysis used in Real-time Assessments is indicated and provided."

Requirement, R4	"The alarm process monitor ***must not*** fail with a simultaneous failure of the Real-time monitoring alarm processor." (Rationale for Requirement R4, paragraph 2)	"The alarm process monitor ***should be designed and implemented such that*** a failure of the alarm process monitor does not cause a simultaneous failure of the Real-time monitoring alarm processor."
	"A stalled Real-time monitoring alarm processor **should not** cause a failure of the alarm process monitor." (paragraph 2)	"A Real-time monitoring alarm processor ***should be designed and implemented such that*** a stall of the Real-time monitoring alarm processor does not cause a simultaneous failure of the alarm process monitor."

Response. Thank you for your comments. The SDT does not believe the suggested change to "adversely affecting Real-time Assessments" provides additional clarity. The SDT has changed *resolve* to *address*, and added clarifying details to the Guidelines section. The SDT has reviewed all proposed revisions to the Guidelines section and made several changes per your recommendations.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes

Comment

In general, Texas RE agrees with the changes made by the SDT to draft standard TOP-010-1. However, Texas RE provides the following comments or suggestions to the proposed standard:

- Texas RE recommends adding the Balancing Authority to the applicability of R3. Some BA tools can be considered a Real-time monitoring tool, for example, the use of SCED in this region.

- Texas RE suggests the SDT consider explicitly stating real-time monitoring in addition to real-time assessments in R1.3. For example, "Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time monitoring and Real-time Assessments. In addition, Texas RE would like to highlight that Texas RE is concerned there is no definitive timeframe provided associated with the actions to resolve issues which may lead to a reliability gap due to a myriad of approaches taken by registered entities. Texas RE supports the RTBPTF recommendations related to real-time monitoring. Specifically, for telemetry data systems:

1) Increase the minimum update frequency for operational reliability data from once every 10 minutes to once every 10 seconds.16

2) Standardize the procedures, processes, and rules governing key data exchange issues.17

3) Institute a requirement for data availability from ICCP or other equivalent systems, based on the ratio of "good" data received (as defined by data quality codes) to total data received. The ratio must exceed 99 percent for 99 percent of the sampled periods during a calendar month. In addition, the ratio must not be less than 99 percent for any 30 consecutive minutes.

4) Establish minimum response times for restoration of data exchange between control centers following the loss of a data link or other problems within the source system. As part of this requirement, a trouble-resolution process standard must be developed that requires all entities responsible for management and maintenance of ICCP or equivalent systems to identify, with data recipients that could be affected by a loss of data exchange capability, a mutually agreeable restoration target time. The standard process must also include service-restoration escalation procedures and prioritization criteria.

- Texas RE noticed an inconsistency in language between the standard requirement language and the rationale discussion for Requirement 1 and Requirement 2 which states, "The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to *operating personnel*." Unfortunately, "operating personnel", is not a defined term and the Requirements specifically states "System Operator". Texas RE recommends that the rational language be changed to be consistent with the standard requirements.

- Texas RE is concerned the data retention for R2 is a rolling 30 days while the retention period for R1 is the current calendar year and one previous calendar year with the exception of operator logs and voice recording which shall be retained or a minimum of 90 calendars days. Texas RE inquires as to why there is a difference in the evidence retention period even though there is very little difference in the measures? Texas RE recommends an evidence retention period of a year for both R1 and R2 because there is no basis

to distinguish actions to address errors in data inputs (R1) and the analysis of the data inputs (R2) and the longer time frame of a year would give the entity more time to resolve data issues. • In the Guidelines and Technical Basis documentation there is a statement: "The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel". Texas RE recommends adding: "including the System Operator" or something to that affect. The standard is applicable to the System Operators; the term "operating personnel" is undefined.	
Response. Thank you for your comments. See responses in the previous section. BAs are not required to perform Real-time Assessments, as defined in the NERC Glossary and specified in other standards. Accordingly, the SDT did not include them in Requirement R3. BA analysis functions and capabilities are addressed in other standards including BAL-005.	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group	
Answer	Yes
Comment	
We suggest to the drafting team to mention more information in the rationale box pertaining to Requirement R1 and its sub-part 1.1 on the expectations for the criteria in reference to evaluating the quality of the real-time data. Additionally, our review group would suggest mentioning the criteria examples spoken of in the drafting team's webinar in the rationale box of this section. The review group's opinion of this is….the criteria examples will give the industry a foundation on how to use various Real-time scenarios to structure their Operational Process or Operational Procedure. In our opinion, Requirement R1 sub-part 1.3 rationale box information (last paragraph) doesn't match the proposed language for that particular section of the Requirement. The Rationale information doesn't clearly state what documentation contains the 'scope of data point information' this proposed language will help clarify. We would ask are you referring to the SAR, or the RTBPTF Report or could it be the FERC Directive. Our review group would suggest mentioning the specific document(s) in the Rationale Section so there will be no misconception on what documentation contains the scope in reference to the data points and how those points should be addressed when providing evidence during an auditing process.	

As for Requirement R2, we would suggest to the drafting team to include the examples provided in their presentation to the Rationale Section. We feel this information will help give some clarity on what the expectations are for the industry pertaining to Requirement R2.

For Requirement R4, we suggest they drafting team include some proposed language that suggests including the ‘alarm process monitor that provide modification’ into their Operational Process or Operation Procedure. We feel the current language suggests that this process doesn’t need to be included in the previously mentioned documentation which could lead to interpretation issues from our perspective.

Response. Thank you for your comments. See response in previous section.

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Answer	Yes

Comment

Revisions to remove much of the very specific requirements is a good change and Hydro One Networks Inc. supports this. In particular, Hydro One Networks Inc. supports the removal of the list of criteria previously stipulated in Draft 1’s R1.1 and R2.1 for evaluating the quality of Real-time data.

Response. Thank you for your comments.

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes

Comment

SRP believes the current draft of TOP-010-1 is a significant improvement on the former draft. SRP recommends that in R1 Part 1.3, R2 Part 2.3, and R3 Part3.3 the verbiage should be changed from “Actions to resolve” to “Actions to address”. The TOP and BA may not be able to resolve all quality issues for all the data it receives but they can address all the data with quality issues. This change would retain the responsibility for compliance with the TOP and BA.

Response. Thank you for your comments. The SDT has changed *resolve* to *address*, and added clarifying details to the Guidelines section.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE IESO Dominion

Answer	Yes

Comment

We support the draft standard TOP-010-1.

Response. Thank you for your comments.

John Fontenot - Bryan Texas Utilities - 1

Answer	Yes

Mark Kenny - Eversource Energy - 3

Answer	Yes

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Answer	Yes

Jared Shakespeare - Peak Reliability - 1	
Answer	Yes
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP	
Answer	Yes

3. Do you agree with the revised Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.
Summary Consideration. The SDT thanks all commenters. The SDT did not make any changes to the proposed Implementation Plan. Comment responses are provided below.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP	
Answer	No
Comment	

Xcel Energy appreciates the fact that the SDT added some additional time to the Implementation Plan for these standards, however we still feel that the implementation timeline is too short. We continue to propose a 60 month implementation timeline as suggested previously by the MRO Standards Review Forum which states:

The implementation plan is too short if entities need to specify, order and deploy new or modified Energy Management Systems (EMS) that can monitor, track, and report real-time data quality and availability in accordance with IRO-018 and TOP-010. Entities should be given an implementation plan with up to 60 months for new EMS software and systems.

The key is to allow entities the proper time to assess their tools and complete the right upgrades once. While prompt actions are good, forcing entities to assess, order, and deploy equipment in 12 or 18 months will lead to errors and possibly more risk of serious outages and problems in the short term.

Response. Thank you for your comments. Based on industry feedback, the SDT believes the 18-month period for implementation provides the necessary time for entities to implement procedures and capabilities to comply with the proposed requirements and addresses the reliability objectives with appropriate urgency. The SDT acknowledges that procurement of a new EMS takes considerable time; however, meeting the requirements in the proposed standard should not require extensive hardware changes, if any.

Thomas Foltz - AEP - 5

Answer	No
Comment	

As the draft standard is currently written, AEP cannot determine the adequacy of the proposed implementation plan. However, if the drafting team were to replace "resolve" with "address" in R1.3 as suggested above, AEP believes the implementation plan would be sufficient.

Response. Thank you for your comments.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Comment	

Southern believes that the implementation date should be pushed back to at least 24 months following regulatory approval to allow time for the industry to determine the appropriate technology that is sufficient for each entity's operations. We also believe that in order to fully comply with the proposed standard, enough time should be allowed for the industry to update their current procedures and/or to create acceptable procedures, provide training to the appropriate System Operators and allow sufficient time for the entities to determine the technology available that is available and appropriate to support their operations, along with the required functionality.

Response. Thank you for your comments. Based on industry feedback, the SDT believes the 18-month period for implementation provides the necessary time for entities to implement procedures and capabilities to comply with the proposed requirements and addresses the reliability objectives with appropriate urgency.

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Comment	

Since we do not agree with the need for these standards, we do not support the proposed implementation plan.	
Response. Thank you for your comments.	

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	No
Comment	
PJM does not support the proposed standards for the reasons noted in 1 and 2 above.	
Likes 1	PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
Response. Thank you for your comments.	

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2	
Answer	No
Comment	
We do not agree with the need for the two standards, and therefore do not agree with any implementation plans.	
Response. Thank you for your 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	No
Comment	

Hydro One Networks Inc. proposes that a period of at least 18 months be provided for entities to implement Operating Processes or Operating Processes. Such an effort is onerous and multiple business units and entities would have to align their practices with one another.

Response. Thank you for your comments. The SDT agrees and has proposed an implementation period of 18 months.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No

Comment

We feel the SDT has made a general assumption that each applicable entity already has the processes, procedures, and infrastructure in place to comply with these requirements. However, we believe entities should have up to 60 months to deploy a new or modified Energy Management System that can monitor, track, and report real-time data quality and availability in accordance with IRO-018 and TOP-010. The key is to allow entities adequate time to assess their tools and complete the right enhancements once. While prompt actions are good practices, forcing entities to assess, order, and deploy equipment within 18 months may lead to unintended consequences.

Response. Thank you for your comments. Based on industry feedback, the SDT believes the 18-month period for implementation provides the necessary time for entities to implement procedures and capabilities to comply with the proposed requirements and addresses the reliability objectives with appropriate urgency. Meeting the requirements in the proposed standard should not require procurement of new EMS or extensive hardware or software changes.

Andrew Pusztai - American Transmission Company, LLC - 1

Answer	Yes

Comment

ATC is in agreement with the Implementation plan for TOP-010-1. IRO-18-1 is not applicable to ATC.

Response. Thank you for your comments.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Comment	
AZPS agrees with the standardization (and extension of 12 month requirements) such that all requirements become effective on the first day of the first calendar quarter that is 18 months after the date these standards are approved.	
Response. Thank you for your comments.	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Comment	
18 month implementation is better than the previous 12 month implementation. thank you.	
Response. Thank you for your comments.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Comment	
Texas RE does not agree with the revised Implementation Plan for the proposed standards. Alternatively, Texas RE recommends one year which should be sufficient time to implement the new standards since entities are currently responsible for certain real-time monitoring processes and procedures.	

Response. Thank you for your comments. Based on industry feedback, the SDT believes the 18-month period for implementation balances the needed urgency with an appropriate amount of time for entities to implement procedures and capabilities to comply with the proposed requirements.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Comment	
Except for those concerns raised in ERCOT's comments above, the proposed Implementation Plan appears reasonable.	
Response. Thank you for your comments.	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Jared Shakespeare - Peak Reliability - 1	
Answer	Yes

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1	
Answer	Yes
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE IESO Dominion	
Answer	Yes
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Mark Kenny - Eversource Energy - 3	
Answer	Yes
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy	
Answer	Yes
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes

4. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

Summary Consideration. The SDT thanks all commenters. The SDT did not make any changes to the VRFs and VSLs. Comment responses are provided below.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No

Comment

We believe that not having good data quality and analysis are a medium risk to BES reliability. However, we disagree that the VRFs for these requirements should be classified as Medium, as the Operating Process or Operating Procedure that support both more falls in-line with the criteria of a low risk violation. Our recommendation is further supported with the definition of a Low VRF, as defined within the NERC Violation Risk Factor and Violation Severity Level Justifications document, which states "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." The nonexistence of a related Operating Process or Procedure will have no impact on the state or BES capability.

Response. Thank you for your comments. Implementation of an Operating Process or Operating Procedure should not be regarded as administrative in nature. Assignment of Medium VRF is appropriate since failure to implement effective procedures for data and analysis quality could impact "the ability to effectively monitor and control the BES."

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Answer	No

Comment

Hydro One Networks Inc. does not support the VSLs, as they are not consistent with the changes made to Draft 2 of the standard. For example, the VSL for R1 assumes that entities would implement one or more of the criteria for evaluating Real-time data quality that have now been removed in Draft 2.	
Response. Thank you for your comments. For assessing degrees of compliance with Requirement R1, the VSL includes the three Requirement Parts as described in the current draft of the standard. Degrees of compliance are not based on specific examples of criteria, which were removed from the requirement and moved to the Guidelines and Technical Basis section in Draft 2.	
Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2	
Answer	No
Comment	
We do not agree with the need for the two standards, and therefore do not agree with any proposed VRFs and VSLs.	
Response. Thank you for your comments.	
William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	No
Comment	
PJM does not support the proposed standards for the reasons noted in 1 and 2 above.	
Likes 1	PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
Response. Thank you for your comments.	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Comment	
Since we do not agree with the need for these standards, we do not support the proposed VRFs and VSLs.	
Response. Thank you for your comments.	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Comment	
Although Southern is encouraged that the SDT has now added some low VRFs/VSLs to the proposed standards, we still maintain that the VRFs and VSLs are too high and should be modified additionally.	
Response. Thank you for your comments. The SDT has carefully reviewed NERC and FERC guidelines and determined that the proposed VRFs and VSLs are in agreement.	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	No
Comment	
The VSL for TOP-010-1 Requirement R4 requires the entity to prove the negative for compliance. It is unknown how an entity would prove the alarm process monitor did not fail unless a tertiary monitor was implemented. Tacoma Power does not believe that this is the intent of the standard.	

Response. Thank you for your comments. The draft RSAW provides compliance guidance including a description of evidence that may be used. Examples of evidence include a system specification for the alarm process monitor, and logs or other evidence that the monitor provided indication during those times (if any) when the Real-time monitoring alarm processor failed.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Comment	
ATC is in agreement with the VRFs/VSLs for TOP-010-1. IRO-18-1 is not applicable to ATC.	
Response. Thank you for your comments.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	Yes
Mark Kenny - Eversource Energy - 3	
Answer	Yes
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE IESO Dominion	
Answer	Yes
Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1	
Answer	Yes
Jared Shakespeare - Peak Reliability - 1	
Answer	Yes
Thomas Foltz - AEP - 5	
Answer	Yes
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP	
Answer	Yes

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC
Comment
The VRFs and VSLs forTOP-010-1 should be no greater or less than those of TOP-003-3, TOP-004.
Response. Thank you for your comments. The SDT has considered VRFs and VSLs of similar TOP and IRO requirements in addition to other NERC and FERC guidelines and determined that the proposed VRFs and VSLs are in agreement.

5. Provide any additional comments for the SDT to consider, if desired.

Summary Consideration. The SDT thanks all commenters. Comment responses are provided below.

John Fontenot - Bryan Texas Utilities - 1
Comment
na
Response

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)
Comment

None.

Response

Andrew Pusztai - American Transmission Company, LLC - 1

Comment

ATC requests a clarification by the SDT in TOP-010-1 on the phrase “affects Real-time Assessments” which is used in sections R1.1.3 and R2.2.3 and the phrase “affecting its Real-time Assessments” in section R3.3.3. Should “affects” be replaced with “effects” or is this correct as written?

Definitions of “affecting”

· Merriam Webster - causing a feeling of sadness or sympathy - evoking a strong emotional response

· Cambridge - causing a strong emotion, especially sadness

· Dictionary.com - moving or exciting the feelings or emotions.

· TheFreeDictionary.com - Inspiring or capable of inspiring strong emotion - moving or stirring the feelings or emotions. - evoking feelings of pity, sympathy, or pathos

Definitions of Effect and Effecting

· Merriam Webster (effect) - change that results when something is done or happens : an event, condition, or state of affairs that is produced by a cause

· Dictionary.com (effect) - something that is produced by an agency or cause; result; consequence - power to produce results; efficacy; force; validity; influence

· Cambridge (effect) - the result of a particular influence; something that happens because of something else:

Response. Thank you for your comments. The SDT does not agree with the suggested change.

Thomas Foltz - AEP - 5

Comment

AEP has chosen to vote negative on TOP-010-1, driven by our concerns regarding R1.3, as expressed in our response to Q2.

Response. Thank you for your comments.

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Comment

On p.12 of the “Guidelines and Technical Basis” document, paragraph 1 defines what is included “Real-time monitoring.” Paragraph 2 goes on to state that there are “functional requirements to perform [Real-time] monitoring… in other standards.” If this is the case, APS recommends the SDT define “Monitoring” as a term in the NERC Glossary as preferable to defining this term in the “Guidelines and Technical Basis” document that is part of the supplemental material in TOP-010.

Response. Thank you for your comments. The SDT determined that defining 'Monitoring' in the NERC Glossary of terms was not necessary to meet the objectives of Project 2009-02 and could have an unintended impact on other standards where the term is used.

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Comment

The rational for TOP-010-1 R1 and R2 indicates that the data of concern for those requirements is the same data that was determined in TOP-003-3. The TOP-003-3 standard basically specifies what data is necessary for the Real-time Assessments and TOP-010-1 specifies the quality of that data. SRP recommends combining the two standards so that there is one that addresses what data is necessary and also specifies the quality of that data. Combining the two standards would clarify that the data referred to in TOP-010-1 is the same as the data referred to in TOP-003-1.

Response. Thank you for your comment. Recent revisions to TOP and IRO standards have resulted in significant changes to these families of standards. The SDT determined when Project 2009-02 was resumed in 2015 that it was straightforward to address the project objectives with new standards.

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Comment

Overall, the second draft has simplified the requirements to an extent. Hydro One Networks Inc. believes that some form of oversight or standardization is required to ensure there is a continuous focus on real time monitoring tools. Data quality measures are appropriate; however, decisions to the degree and method of verification should be left to the discretion of each entity as this will, to an extent, depend on the level of system complexity. A simple system can be tuned to a small error (or convergence) while a complicated system may require a larger allowance.

R1 and R2 – Since the functional requirements, VRFs, and Time Horizons are identical, these two requirements could be combined into one requirement and made applicable to both the Transmission Owner and Balancing Authority.

R2.2 - The wording in R2.2 could be modified to align with that of R1.3, and read, "Actions to resolve Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects **Real-time Assessments**.

R4 - The wording could be improved as follows: "*Each Transmission Operator and Balancing Authority shall **have alarm process monitoring** that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred*"

Response. Thank you for your comments. The SDT agrees that more prescriptive requirements will not be effective in addressing the project's objectives. Requirement R2 is unique to BAs because they do not perform Real-time Assessments as defined in the NERC Glossary and specified in other standards. The SDT does not believe the suggested change to R4 provides additional clarity.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Comment	
(1) We request the SDT provide additional rationale on the need to develop new reliability standards, when we feel many current and approved future standards could be enhanced to support the intent of the SAR. Other documentation, such as Reliability Guidelines, could be used to elaborate on specific details and concerns regarding data and analytical qualities. (2) We thank the SDT for this opportunity to comments on these standards.	
Response. Thank you for your comments. Recent revisions to TOP and IRO standards have resulted in significant changes to these families of standards. The SDT determined when Project 2009-02 was resumed in 2015 that a straightforward approach to address the project objectives would be through the development of new standards.	

End of Report

Standard Development Timeline

The drafting team maintained this section while developing the standard. It will be removed when the standard becomes effective.

Description of Current Draft

This draft is the third posting of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	July 16 - August 17, 2015
45-day formal comment period with initial ballot	September 24 - November 9, 2015
45-day formal comment period with additional ballot	December 9, 2015 - January 26, 2016

Anticipated Actions	Date
10-day final ballot	February 2016
NERC Board (Board) adoption	May 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:** **Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **IRO-018-1**
3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirement R1: The Reliability Coordinator (RC) uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the RC shall include actions to address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by IRO-010-2 Requirement R3 Part 3.2 provided that this process addresses Real-time data quality issues.

The revision in Part 1.3 to address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R1. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator or supporting logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R2: Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

R2. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

2.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

2.3. Actions to address analysis quality issues affecting its Real-time Assessments.

M2. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R2. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R3: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

R3. Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Reliability Coordinator shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 it was compliant for the full-time period since the last audit.

The Reliability Coordinator 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 Reliability Coordinator shall retain evidence of compliance for Requirements R1 and R3 and Measures M1 and M3 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall retain evidence of compliance for Requirement R2 and Measure M2 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator 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 Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes 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 Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of

		analysis used in its Real-time Assessments did not include one of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include two of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.
R3.	N/A	N/A	The Reliability Coordinator has an alarm process monitor but the alarm process monitor did not provide a notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The Reliability Coordinator does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability Standards. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The RC uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform monitoring and Real-time Assessments appear in other Reliability Standards.

The RC's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed IRO-018-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the RC shall include actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The RC's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the RC to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the RC;

- Following processes established for resolving data conflicts as specified in IRO-010-1a, IRO-010-2, or other applicable Reliability Standards;
- Taking corrective actions on the RC's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the RC's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R2

Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the types of criteria used to evaluate the quality of analysis used in Real-time Assessments may include solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R3

Requirement R3 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that a stall of the Real-time monitoring alarm processor does not cause a failure of the alarm process monitor.

Rationale

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

Standard Development Timeline

~~This~~ The drafting team maintained this section while developing the standard. It will be removed when the standard becomes effective.

Description of Current Draft

This draft is the ~~second~~ third posting of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	July 16 - August 17, 2015
45-day formal comment period with initial ballot	September 24 - November 9, 2015
45-day formal comment period with additional ballot	December 9, 2015 - January 26, 2016

Anticipated Actions	Date
~~45-day formal comment period with additional ballot~~	~~December 2015~~
10-day final ballot	~~February~~ February 2016
NERC Board (Board) adoption	May 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:** **Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **IRO-018-1**
3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirement R1: The Reliability Coordinator (RC) uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability ~~standards~~Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the RC shall include actions to ~~resolve~~address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by IRO-010-2 Requirement R3 Part 3.2 provided that this process addresses~~resolves~~ Real-time data quality issues.

The revision in Part 1.3 to ~~resolve~~address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R1. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating

Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to ~~resolve~~ address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator or supporting logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R2: Requirement R2 ensures RCs have procedures ~~-~~to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability ~~standards~~Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

R2. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

2.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

2.3. Actions to ~~resolve~~address analysis quality issues affecting its Real-time Assessments.

M2. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R2. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R3: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

R3. Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Reliability Coordinator shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 it was compliant for the full-time period since the last audit.

The Reliability Coordinator 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 Reliability Coordinator shall retain evidence of compliance for Requirements R1 and R3~~–~~ and Measures M1 and M3 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall retain evidence of compliance for Requirement R2 and Measure M2 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator 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 Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes 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 Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of

		analysis used in its Real-time Assessments did not include one of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include two of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.
R3.	N/A	N/A	The Reliability Coordinator has an alarm process monitor but the alarm process monitor did not provide a notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The Reliability Coordinator does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability ~~standards~~Standards. As used in TOP and IRO Reliability ~~standards~~Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include~~s~~ the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The RC uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform monitoring and Real-time Assessments appear in other Reliability ~~standards~~Standards.

The RC's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed IRO-018-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, which may include~~such as~~:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the RC shall include actions to ~~resolve~~address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The RC's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the RC to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the RC;
- Following processes established for resolving data conflicts as specified in IRO-010-1a, IRO-010-2, or other applicable Reliability Standards;
- Taking corrective actions on the RC's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the RC's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to ~~resolve~~address data quality issues in an appropriate timeframe.

Requirement R2

Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability ~~standards~~Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the type of criteria used to evaluate the quality of analysis used in Real-time Assessments may include~~The entity must use appropriate quality criteria based on the analysis capabilities used to perform Real-time Assessments, such as~~ solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must ~~include provisions for~~describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R3

Requirement R3 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that ~~stall~~a stall~~ed~~ of the Real-time monitoring alarm processor ~~must~~ does not cause a failure of the alarm process monitor.

Rationale

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

Standard Development Timeline

The drafting team maintained this section while developing the standard. It will be removed when the standard becomes effective.

Description of Current Draft

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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:** **Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **TOP-010-1**
3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1. Transmission Operators
   4.1.2. Balancing Authorities
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirement R1: The Transmission Operator (TOP) uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the TOP shall include actions to address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2, provided that this process addresses Real-time data quality issues.

The revision in Part 1.3 to address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R1. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating

Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Transmission Operator shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R2: The Balancing Authority (BA) uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 of this standard specifies the BA shall include actions to address Real-time data quality issues affecting its analysis functions in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2 provided that this process addresses Real-time data quality issues.

The revision in Part 2.3 to address Real-time data quality issues *when data quality affects its analysis functions* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R2. Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. Criteria for evaluating the quality of Real-time data;

2.2. Provisions to indicate the quality of Real-time data to the System Operator; and

2.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.

M2. Each Balancing Authority shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Balancing Authority implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R3: Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

R3. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

3.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

3.3. Actions to address analysis quality issues affecting its Real-time Assessments.

M3. Each Transmission Operator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R3. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R3; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R4: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

R4. Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Transmission Operator and Balancing Authority shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 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 applicable entity shall retain evidence of compliance for Requirements R1, R2, and R4, and Measures M1, M2, and M4 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall retain evidence of compliance for Requirement R3 and Measure M3 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity 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.

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 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 Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the

		Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include two of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.
R3.	N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 through Part 3.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of

				analysis used in its Real-time Assessments.
R4.	N/A	N/A	The responsible entity has an alarm process monitor but the alarm process monitor did not provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The responsible entity does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability Standards. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The TOP uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform monitoring and Real-time Assessments appear in other Reliability Standards.

The TOP's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the TOP shall include actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The TOP's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the TOP to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the TOP;
- Following processes established for resolving data conflicts as specified in TOP-003-3, or other applicable Reliability Standards;
- Taking corrective actions on the TOP's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the TOP's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R2

The BA uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability Standards.

The BA's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R2 Part 2.1. The criteria supports identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 specifies the BA shall include in its Operating Process or Operating Procedure actions to address Real-time data quality issues when data quality affects its analysis functions. Requirement R2 Part 2.3 is focused on addressing data point quality issues affecting analysis functions. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R2 Part 2.3.

The BA's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the BA to meet its obligations for performing its analysis functions. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the BA;

- Following processes established for resolving data conflicts as specified in TOP-003-3 or other applicable Reliability Standards;
- Taking corrective actions on the BA's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the BA's analysis functions; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the analysis quality so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R3

Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments may include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the types of criteria used to evaluate the quality of analysis used in Real-time Assessments may include solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R4

Requirement R4 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that a stall of the Real-time monitoring alarm processor does not cause a failure of the alarm process monitor.

Rationale

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

Standard Development Timeline

~~This~~The drafting team maintained this section while developing the standard. It will be removed when the standard becomes effective.

Description of Current Draft

This draft is the ~~second~~ third posting of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	July 16 - August 17, 2015
45-day formal comment period with initial ballot	September 24 - November 9, 2015
45-day formal comment period with additional ballot	December 9, 2015 - January 26, 2016

Anticipated Actions	Date
~~45-day formal comment period with additional ballot~~	~~December 2015~~[MO1]
10-day final ballot	February 2016
NERC Board (Board) adoption	May 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:** **Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **TOP-010-1**
3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Operators
     - **4.1.2.** Balancing Authorities
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirement R1: The Transmission Operator (TOP) uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability ~~standards~~Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the TOP shall include actions to ~~resolve~~address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2, provided that this process ~~resolves~~ addresses Real-time data quality issues.

The revision in Part 1.3 to ~~resolve~~address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R1. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating

Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to ~~resolve~~address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Transmission Operator shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R2: The Balancing Authority (BA) uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability ~~standards~~Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 of this standard specifies the BA shall include actions to ~~resolve Real~~address Real-time data quality issues affecting its analysis functions in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2 provided that this process ~~resolves~~ addresses Real-time data quality issues.

The revision in Part 2.3 to ~~resolve~~address Real-time data quality issues *when data quality affects its analysis functions* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

R2. Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating

Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. Criteria for evaluating the quality of Real-time data;

2.2. Provisions to indicate the quality of Real-time data to the System Operator; and

2.3. Actions to ~~resolve~~address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.

M2. Each Balancing Authority shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Balancing Authority implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R3: Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability ~~standards~~Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

R3. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

3.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

3.3. Actions to ~~resolve~~address analysis quality issues affecting its Real-time Assessments.

M3. Each Transmission Operator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R3. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R3; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R4: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

R4. Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Transmission Operator and Balancing Authority shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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~~–~~ 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 applicable entity shall retain evidence of compliance for Requirements R1, R2, and R4, and Measures M1, M2, and M4 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall retain evidence of compliance for Requirement R3 and Measure M3 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity 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.

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 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 Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the

		Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include two of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.
R3.	N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 through Part 3.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of

				analysis used in its Real-time Assessments.
R4.	N/A	N/A	The responsible entity has an alarm process monitor but the alarm process monitor did not provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The responsible entity does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability ~~standards~~Standards. As used in TOP and IRO Reliability ~~standards~~Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include~~s~~ the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The TOP uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform monitoring and Real-time Assessments appear in other Reliability ~~standards~~Standards.

The TOP's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, ~~such as~~which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the TOP shall include actions to ~~resolve~~address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The TOP's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the TOP to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the TOP;
- Following processes established for resolving data conflicts as specified in TOP-003-3, or other applicable Reliability Standards;
- Taking corrective actions on the TOP's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the TOP's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to ~~resolve~~address data quality issues in an appropriate timeframe.

Requirement R2

The BA uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability ~~standards~~Standards.

The BA's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R2 Part 2.1. The criteria supports identification of applicable data quality issues, ~~such as~~which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 specifies the BA shall include in its Operating Process or Operating Procedure actions to ~~resolve~~address- Real-time data quality issues when data quality affects its analysis functions. Requirement R2 Part 2.3 is focused on addressing data point quality issues affecting analysis functions. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R2 Part 2.3.

The BA's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the BA to meet its obligations for performing its analysis functions. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the BA;

- Following processes established for resolving data conflicts as specified in TOP-003-3 or other applicable Reliability Standards;
- Taking corrective actions on the BA's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the BA's analysis functions; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the analysis quality so that effective actions can be taken to ~~resolve~~address data quality issues in an appropriate timeframe.

Requirement R3

Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability ~~standards~~Standards. Examples of the types of analysis used in Real-time Assessments may include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the type of criteria used to evaluate the quality of analysis used in Real-time Assessments may include ~~The entity must use appropriate quality criteria based on the analysis capabilities used to perform Real-time Assessments, such as~~ solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must ~~include provisions for~~describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R4

Requirement R4 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that a stall~~ed~~ of the -Real-time monitoring alarm processor ~~should~~ does not cause a failure of the alarm process monitor.

Rationale

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

Implementation Plan

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Requested Approvals

- IRO-018-1 - Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
- TOP-010-1 - Real-time Reliability Monitoring and Analysis Capabilities

Requested Retirements

- None

Prerequisite Approval

Rationale: Due to regulatory approval of TOP-003-3, the prerequisite approval from the initial draft Implementation Plan has been satisfied.

- None

Revisions to Defined Terms in the NERC Glossary

None

Applicable Entities

- Reliability Coordinators
- Transmission Operators
- Balancing Authorities

Effective Date

Rationale: The Implementation Plan has been revised and simplified such that all requirements become effective 18 months following regulatory approval. The implementation period provides entities time to implement Operating Processes or Operating Procedures and enhance functions of their Real-time monitoring systems, as necessary.

IRO-018-1

- All Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, all Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

TOP-010-1

- All Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, all Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Requested Approvals

- IRO-018-1 - Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
- TOP-010-1 - Real-time Reliability Monitoring and Analysis Capabilities

Requested Retirements

- None

Prerequisite Approval

Rationale: Due to regulatory approval of TOP-003-3, the prerequisite approval from the initial draft Implementation Plan has been satisfied.

- None

Revisions to Defined Terms in the NERC Glossary

None

Applicable Entities

- Reliability Coordinators
- Transmission Operators
- Balancing Authorities

Effective Date

Rationale: The Implementation Plan has been revised and simplified such that all requirements become effective 18 months following regulatory approval. The implementation period provides entities time to implement Operating Processes or Operating Procedures and enhance functions of their Real-time monitoring systems, as necessary.

IRO-018-1

- All Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, all Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

TOP-010-1

- All Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, all Requirements shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Order No. 693 Citation	Directive/Guidance	Resolution
P 905-906	Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.	Proposed IRO-018-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the Reliability Coordinator's (RC) monitoring and analysis capabilities. The monitoring and analysis capabilities required by proposed IRO-018-1 and other IRO standards discussed below ensure RCs have the capabilities to maintain Real-time situational awareness. **Monitoring Capabilities** Requirement R1 addresses the quality of the Real-time data needed by the RC to perform its monitoring and Real-time Assessments. Each RC is required to implement a documented procedure for addressing Real-time data quality issues. The procedure must include criteria for evaluating Real-time data quality, provisions for indicating data quality to the System Operator, and actions to address Real-time data quality issues when data quality affects Real-time Assessments. Requirement R3 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring RCs to use an alarm process monitor. Requirements for the RC to perform Real-time monitoring are specified in IRO-002-2, IRO-002-4, and IRO-003-2. ***Proposed IRO-018-1*** **R1.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time

Order No. 693 Citation	Directive/Guidance	Resolution
		monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating the quality of Real-time data; **1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and **1.3.** Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. **R3.** Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***IRO-002-2*** **R5.** Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. ***IRO-003-2*** **R1.** Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or

Order No. 693 Citation	Directive/Guidance	Resolution
		unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. ***IRO-002-4*** **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. **<u>Analysis Capabilities</u>** Requirement R2 addresses the quality of the analysis used by the RC to perform its Real-time Assessments. Each RC is required to implement a documented procedure to address the quality of the analysis used in its Real-time Assessments. The procedure must include criteria for evaluating the quality of analysis used in Real-time Assessments, provisions for indicating the quality of analysis, and actions to address analysis quality issues affecting its Real-time Assessments. Requirements for the RC to perform Real-time Assessments are specified in IRO-008-1 and IRO-008-2. ***Proposed IRO-018-1*** **R2.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include:

Order No. 693 Citation	Directive/Guidance	Resolution
		2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments; **2.2** Provisions to indicate the quality of analysis used in its Real-time Assessments; and **2.3.** Actions to address analysis quality issues affecting its Real-time Assessments. ***IRO-008-1*** **R2.** Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. ***Definition of 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.) ***IRO-008-2*** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Order No. 693 Citation	Directive/Guidance	Resolution
P 1660	We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.	Proposed TOP-010-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the monitoring and analysis capabilities used by Transmission Operators (TOPs) and Balancing Authorities (BAs). The monitoring and analysis capabilities required by TOP-010-1 and other TOP standards discussed below ensure TOPs and BAs have the capabilities to maintain Real-time situational awareness. **<u>Monitoring Capabilities</u>** Requirements R1 and R2 address the quality of the Real-time data needed by TOPs and BAs to perform their Real-time monitoring and Real-time analysis. Each TOP and BA is required to implement a documented procedure for addressing Real-time data quality issues. The procedure must include criteria for evaluating Real-time data quality, provisions for indicating data quality to the System Operator, and actions to address Real-time data quality issues when data quality affects analysis. Requirement R4 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring TOPs and BAs to use an alarm process monitor. Requirements for TOPs to perform Real-time monitoring are specified in TOP-001-3 and TOP-006-2. Requirements for BAs to perform Real-time monitoring are specified in TOP-006-2, TOP-001-3k and BAL standards. ***Proposed TOP-010-1*** **R1.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time

Order No. 693 Citation	Directive/Guidance	Resolution
		monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating the quality of Real-time data; **1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and **1.3.** Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. **R2.** Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: **2.1** Criteria for evaluating the quality of Real-time data; **2.2** Provisions to indicate the quality of Real-time data to the System Operator; and **2.3** Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data. **R4.** Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***TOP-006-2*** **R1.** Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

Order No. 693 Citation	Directive/Guidance	Resolution
		1.1. - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2.** - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. ***TOP-001-3*** **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. **Analysis Capabilities** Requirement R3 addresses the quality of the analysis used by the TOP to perform its Real-time Assessments. Each TOP is required to implement a documented procedure to address the quality of the analysis used in its Real-time Assessments. The procedure must include criteria for evaluating the quality of

Order No. 693 Citation	Directive/Guidance	Resolution
		analysis used in Real-time Assessments, provisions for indicating the quality of analysis, and actions to address analysis quality issues affecting its Real-time Assessments. Requirements for the TOP to perform Real-time Assessments are specified in TOP-003-3. ***Proposed TOP-010-1*** **R3.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: **3.1.** Criteria for evaluating the quality of any analysis used in its Real-time Assessments; **3.2.** Provisions to indicate the quality of analysis used in its Real-time Assessments; and **3.3.** Actions to address analysis quality issues affecting its Real-time Assessments. ***Definition of 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.) ***TOP-001-3*** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Order No. 693 Citation	Directive/Guidance	Resolution
P 1875	...[w]e direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1 to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.	The directive was considered in developing the scope of Project 2009-02. NERC believes TOP, IRO, and VAR standards address the directive as discussed below. Accordingly, additional requirements were not developed in Project 2009-02. RCs and TOPs are required to periodically perform Real-time Assessments consisting of an evaluation of system conditions "to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions." Entities must use whatever analysis is necessary to obtain an evaluation of system conditions, which may include real-time voltage stability analysis. Real-time Assessments assist operators in maintaining operations within established SOLs and IROLs, to include voltage stability criteria. Requirements for performing Real-time Assessments are contained in IRO-008-1, IRO-008-2, and TOP-001-3 Reliability Standards as discussed above. VAR-001-1 was revised in Project 2013-04. The resulting standard, VAR-001-4, did not include an explicit requirement for periodic performance of voltage stability analysis because "such analysis would be performed pursuant to the SOL methodology developed under FAC standards."[1] VAR-001-4 requirement R1 specifies the TOP must establish a system voltage schedule as part of its plan to operate within SOLs and IROLs. ***VAR-001-4*** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate

[1] Reliability Standard VAR-001-4.1, Guidelines and Technical Basis section, page 13. Available at: http://www.nerc.com/pa/Stand/Reliability%20Standards/VAR-001-4.1.pdf

Order No. 693 Citation	Directive/Guidance	Resolution
		within System Operating Limits and Interconnection Reliability Operating Limits. **1.1.** Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

Order No. 693 Citation	Directive/Guidance	Resolution
P 905-906	Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.	Proposed IRO-018-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the Reliability Coordinator's (RC) monitoring and analysis capabilities. The monitoring and analysis capabilities required by proposed IRO-018-1 and other IRO standards discussed below ensure RCs have the capabilities to maintain Real-time situational awareness. **<u>Monitoring Capabilities</u>** Requirement R1 addresses the quality of the Real-time data needed by the RC to perform its monitoring and Real-time Assessments. Each RC is required to implement a documented procedure for addressing Real-time data quality issues. The procedure must include criteria for evaluating Real-time data quality, provisions for indicating data quality to the System Operator, and actions to ~~resolve~~address Real-time data quality issues when data quality affects Real-time Assessments. Requirement R3 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring RCs to use an alarm process monitor. Requirements for the RC to perform Real-time monitoring are specified in IRO-002-2, IRO-002-4, and IRO-003-2. ***Proposed IRO-018-1*** **R1.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time

Order No. 693 Citation	Directive/Guidance	Resolution
		monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating the quality of Real-time data; **1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and **1.3.** Actions to ~~resolve~~address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. **R3.** Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***IRO-002-2*** **R5.** Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. ***IRO-003-2*** **R1.** Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or

Order No. 693 Citation	Directive/Guidance	Resolution
		unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. ***IRO-002-4*** **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. **Analysis Capabilities** Requirement R2 addresses the quality of the analysis used by the RC to perform its Real-time Assessments. Each RC is required to implement a documented procedure to address the quality of the analysis used in its Real-time Assessments. The procedure must include criteria for evaluating the quality of analysis used in Real-time Assessments, provisions for indicating the quality of analysis, and actions to ~~resolve~~address analysis quality issues affecting its Real-time Assessments.~~.~~ Requirements for the RC to perform Real-time Assessments are specified in IRO-008-1 and IRO-008-2. ***Proposed IRO-018-1*** **R2.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include:

Order No. 693 Citation	Directive/Guidance	Resolution
		2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments; **2.2** Provisions to indicate the quality of analysis used in its Real-time Assessments; and **2.3.** Actions to ~~resolve~~address analysis quality issues affecting its Real-time Assessments. ***IRO-008-1*** **R2.** Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. ***Definition of 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.) ***IRO-008-2*** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Order No. 693 Citation	Directive/Guidance	Resolution
P 1660	We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.	Proposed TOP-010-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the monitoring and analysis capabilities used by Transmission Operators (TOPs) and Balancing Authorities (BAs). The monitoring and analysis capabilities required by TOP-010-1 and other TOP standards discussed below ensure TOPs and BAs have the capabilities to maintain Real-time situational awareness. **Monitoring Capabilities** Requirements R1 and R2 address the quality of the Real-time data needed by TOPs and BAs to perform their Real-time monitoring and Real-time analysis. Each TOP and BA is required to implement a documented procedure for addressing Real-time data quality issues. The procedure must include criteria for evaluating Real-time data quality, provisions for indicating data quality to the System Operator, and actions to ~~resolve~~address Real-time data quality issues when data quality affects analysis. Requirement R4 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring TOPs and BAs to use an alarm process monitor. Requirements for TOPs to perform Real-time monitoring are specified in TOP-001-3 and TOP-006-2. Requirements for BAs to perform Real-time monitoring are specified in TOP-006-2, TOP-001-3k and BAL standards. ***Proposed TOP-010-1*** **R1.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time

Order No. 693 Citation	Directive/Guidance	Resolution
		monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating the quality of Real-time data; **1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and **1.3.** Actions to ~~resolve~~address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. **R2.** Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: **2.1** Criteria for evaluating the quality of Real-time data; **2.2** Provisions to indicate the quality of Real-time data to the System Operator; and **2.3** Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data. **R4.** Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***TOP-006-2*** **R1.** Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

Order No. 693 Citation	Directive/Guidance	Resolution
		1.1. - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2.** - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. ***TOP-001-3*** **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. **<u>Analysis Capabilities</u>** Requirement R3 addresses the quality of the analysis used by the TOP to perform its Real-time Assessments. Each TOP is required to implement a documented procedure to address the quality of the analysis used in its Real-time Assessments. The procedure must include criteria for evaluating the quality of

Order No. 693 Citation	Directive/Guidance	Resolution
		analysis used in Real-time Assessments, provisions for indicating the quality of analysis, and actions to ~~resolve~~address analysis quality issues affecting its Real-time Assessments. Requirements for the TOP to perform Real-time Assessments are specified in TOP-003-3. ***Proposed TOP-010-1*** **R3.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: **3.1.** Criteria for evaluating the quality of any analysis used in its Real-time Assessments; **3.2.** Provisions to indicate the quality of analysis used in its Real-time Assessments; and **3.3.** Actions to ~~resolve~~address analysis quality issues affecting its Real-time Assessments. ***Definition of 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.) ***TOP-001-3*** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Order No. 693 Citation	Directive/Guidance	Resolution
P 1875	...[w]e direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1 to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.	The directive was considered in developing the scope of Project 2009-02. NERC believes TOP, IRO, and VAR standards address the directive as discussed below. Accordingly, additional requirements were not developed in Project 2009-02. RCs and TOPs are required to periodically perform Real-time Assessments consisting of an evaluation of system conditions "to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions." Entities must use whatever analysis is necessary to obtain an evaluation of system conditions, which may include real-time voltage stability analysis. Real-time Assessments assist operators in maintaining operations within established SOLs and IROLs, to include voltage stability criteria. Requirements for performing Real-time Assessments are contained in IRO-008-1, IRO-008-2, and TOP-001-3 Reliability Standards as discussed above. VAR-001-1 was revised in Project 2013-04. The resulting standard, VAR-001-4, did not include an explicit requirement for periodic performance of voltage stability analysis because "such analysis would be performed pursuant to the SOL methodology developed under FAC standards."[1] VAR-001-4 requirement R1 specifies the TOP must establish a system voltage schedule as part of its plan to operate within SOLs and IROLs. ***VAR-001-4*** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate

[1] Reliability Standard VAR-001-4.1, Guidelines and Technical Basis section, page 13. Available at: http://www.nerc.com/pa/Stand/Reliability%20Standards/VAR-001-4.1.pdf

Order No. 693 Citation	Directive/Guidance	Resolution
		within System Operating Limits and Interconnection Reliability Operating Limits. **1.1.** Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

Standards Announcement

2009-02 Real-time Reliability Monitoring and Analysis Capabilities IRO-018-1 and TOP-010-1

Final Ballots Open through February 26, 2016

Now Available * UPDATED

Final ballots for **IRO-018-1 - Reliability Coordinator Real-time Monitoring and Analysis Capabilities** and **TOP-010-1 - Real-time Reliability Monitoring and Analysis Capabilities** are open through **8 p.m. Eastern, Friday, February 26, 2016**.

Balloting

In the final ballots, votes are counted by exception. Only members of the ballot pools may cast a vote. All ballot pool members may change their previously cast votes. 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 standards here. If you experience any difficulties in using the Standards Balloting & Commenting System (SBS), contact Nasheema Santos.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error message, 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 standards will be posted and announced after the ballots close. If approved, the standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

NERC
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Standards Announcement

2009-02 Real-time Reliability Monitoring and Analysis Capabilities IRO-018-1 and TOP-010-1

Final Ballots Open through February 26, 2016

Now Available

Final ballots for **IRO-018-1 - Reliability Coordinator Real-time Monitoring and Analysis Capabilities** and **TOP-010-1 - Real-time Reliability Monitoring and Analysis Capabilities** are open through **8 p.m. Eastern, Friday, February 26, 2016**.

Balloting

In the final ballots, votes are counted by exception. Only members of the ballot pools may cast a vote. All ballot pool members may change their previously cast votes. 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.

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Next Steps

The voting results for the standards will be posted and announced after the ballots close. If approved, the standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

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For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

Standards Announcement

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities IRO-018-1 and TOP-010-1

Final Ballot Results

Now Available

Final ballots for **IRO-018-1 – Reliability Coordinator Real-time Monitoring and Analysis Capabilities** and **TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities** concluded **8 p.m. Eastern, Friday, February 26, 2016.**

The standards received sufficient affirmative votes for approval. Voting statistics are listed below, and the following links provide detailed results:

- IRO-018-1
- TOP-010-1

Standard	Quorum / Approval
IRO-018-1	88.36% / 75.68%
TOP-010-1	87.79% / 73.87%

Next Steps
The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

BALLOT RESULTS

Ballot Name: 2009-02 Real-time Monitoring and Analysis Capabilities IRO-018-1 FN 3 ST
Voting Start Date: 2/17/2016 10:27:54 AM
Voting End Date: 2/26/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 258
Total Ballot Pool: 292
Quorum: 88.36
Weighted Segment Value: 75.68

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	73	1	40	0.8	10	0.2	0	14	9
Segment: 2	10	0.9	4	0.4	5	0.5	0	1	0
Segment: 3	68	1	33	0.786	9	0.214	0	16	10
Segment: 4	21	1	13	0.813	3	0.188	0	2	3
Segment: 5	63	1	30	0.789	8	0.211	0	20	5
Segment: 6	47	1	22	0.759	7	0.241	0	12	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	1	0.1	1	0.1	0	0	0
Segment: 9	2	0.1	1	0.1	0	0	0	0	1

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Segment: 10	6	0.6	6	0.6	0	0	0	0	0
Totals:	292	6.8	150	5.146	43	1.654	0	65	34

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		Abstain	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	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Abstain	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	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	Chris de Graffenried		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		Abstain	N/A
1	Duke Energy	Doug Hils		None	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	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	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	Abstain	N/A

1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		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		None	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	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	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		None	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
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Negative	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	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Abstain	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	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
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		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		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A

1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	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	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		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	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		Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Negative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Negative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A

3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Valerie Reis		None	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi	Pat Harrington	Abstain	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		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		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	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Abstain	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit	Karie Barczak		None	N/A

	Edison Company				
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		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	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		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	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	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		Abstain	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	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		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Abstain	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Abstain	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	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		Abstain	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A

3	Southern Company - Alabama Power Company	R. Scott Moore		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 Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	N/A
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
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		None	N/A

4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	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	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		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	Avista - Avista Corporation	Steve Wenke		Abstain	N/A
5	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Abstain	N/A

5	Bonneville Power Administration	Francis Halpin		Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Abstain	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	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		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Abstain	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Great Plains Energy - Kansas City Power	Harold Wyble	Douglas Webb	Affirmative	N/A

	and Light Co.				
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		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		Abstain	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	NB Power Corporation	Rob Vance		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		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Platte River Power	Tyson Archie		Affirmative	N/A

	Authority				
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		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 Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Seattle City Light	Mike Haynes	Ginette Lacasse	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	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		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A

5	WEC Energy Group, Inc.	Linda Horn		Negative	N/A
5	Westar Energy	stephanie johnson		Abstain	N/A
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Abstain	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Abstain	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	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	Douglas Webb	Affirmative	N/A

6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Iberdrola - New York State Electric and Gas Corporation	Julie King		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		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		Negative	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.	Adam Menendez		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade	Karla Jara		Negative	N/A

	LLC				
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		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		None	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		Affirmative	N/A
6	Westar Energy	Megan Wagner		Abstain	N/A
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Negative	N/A
8	David Kiguel	David Kiguel		Negative	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		None	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	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

Previous 1 Next

Showing 1 to 292 of 292 entries

BALLOT RESULTS

Ballot Name: 2009-02 Real-time Monitoring and Analysis Capabilities TOP-010-1 FN 3 ST
Voting Start Date: 2/17/2016 10:28:22 AM
Voting End Date: 2/26/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 266
Total Ballot Pool: 303
Quorum: 87.79
Weighted Segment Value: 73.86

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	79	1	49	0.778	14	0.222	0	6	10
Segment: 2	10	0.9	4	0.4	5	0.5	0	1	0
Segment: 3	69	1	40	0.769	12	0.231	0	6	11
Segment: 4	21	1	14	0.778	4	0.222	0	0	3
Segment: 5	63	1	39	0.78	11	0.22	0	8	5
Segment: 6	51	1	28	0.718	11	0.282	0	5	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	1	0.1	1	0.1	0	0	0
Segment: 9	2	0.1	1	0.1	0	0	0	0	1

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Segment: 10	6	0.6	6	0.6	0	0	0	0	0
Totals:	303	6.8	182	5.023	58	1.777	0	26	37

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	Ameren - Ameren Services	Eric Scott		Negative	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		Negative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A

1	Beaches Energy Services	Don Cuevas		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	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	Chris de Graffenried		Affirmative	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		Abstain	N/A
1	Duke Energy	Doug Hils		None	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	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	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	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Iberdrola - Central Maine Power Company	Joe Turano		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Negative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	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	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	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		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	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.	Charles Raney		Negative	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	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Abstain	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	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
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		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		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative	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		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	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		Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A

2	Independent Electricity System Operator	Leonard Kula		Negative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Negative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Negative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	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	Valerie Reis		None	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi	Pat Harrington	Abstain	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		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		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	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	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
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
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		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	N/A
3	Grand River Dam Authority	Jeff Wells		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		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A

3	JEA	Garry Baker		None	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	Scott Miller	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		Negative	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	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		None	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	PHI - Potomac Electric Power Co.	Mark Yerger		Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A

3	PNM Resources	Michael Mertz		None	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	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		Abstain	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	N/A
3	Southern Indiana Gas and Electric Co.	Jim Cox		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Negative	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		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	Westar Energy	Bo Jones		Negative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	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	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
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		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	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	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		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative	N/A

4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	N/A
5	AEP	Thomas Foltz		Affirmative	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	Avista - Avista Corporation	Steve Wenke		Abstain	N/A
5	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	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		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Abstain	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	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	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Abstain	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	N/A
5	Florida Municipal Power Agency	David Schumann		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		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		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	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		Negative	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		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 Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Seattle City Light	Mike Haynes	Ginette Lacasse	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A

5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Negative	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		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	Westar Energy	stephanie johnson		Negative	N/A
6	AEP - AEP Marketing	Edward P Cox		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		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		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs	Shannon Fair		Affirmative	N/A

	Utilities				
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Abstain	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	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	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Iberdrola - New York State Electric and Gas Corporation	Julie King		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		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		Negative	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.	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	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	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		None	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A

6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Negative	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		Negative	N/A
6	Westar Energy	Megan Wagner		Negative	N/A
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Negative	N/A
8	David Kiguel	David Kiguel		Negative	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		None	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	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

Showing 1 to 303 of 303 entries

Exhibit I

Standard Drafting Team Roster

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Drafting Team Roster

Project 2009-02 Real-time Monitoring and Analysis Capabilities

	Participant	Entity
Chair	Saad Malik	Peak Reliability
Vice Chair	Andrew Pankratz	Florida Power & Light
Members	Charles Abell	Ameren
	Scott Aclin	Southwest Power Pool
	Phil Hart	AECI
	T.J. (Tim) Kucey	PSEG Fossil, LLC
	Alan Martin	Southern Company Transmission
	Bert Peters	Arizona Public Service
	Sarma Nuthalapati	Electric Reliability Council of Texas
	Jim Useldinger	Kansas City Power and Light
NERC Staff	Mark Olson – Senior Standards Developer	North American Electric Reliability Corporation
	Lauren Perotti – NERC Legal	North American Electric Reliability Corporation