Real-Time Tools Survey Analysis and Recommendations

Final Report

March 13, 2008

Prepared by the

Real-Time Tools Best Practices Task Force

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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

[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

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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**
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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
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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
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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.

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[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.

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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.

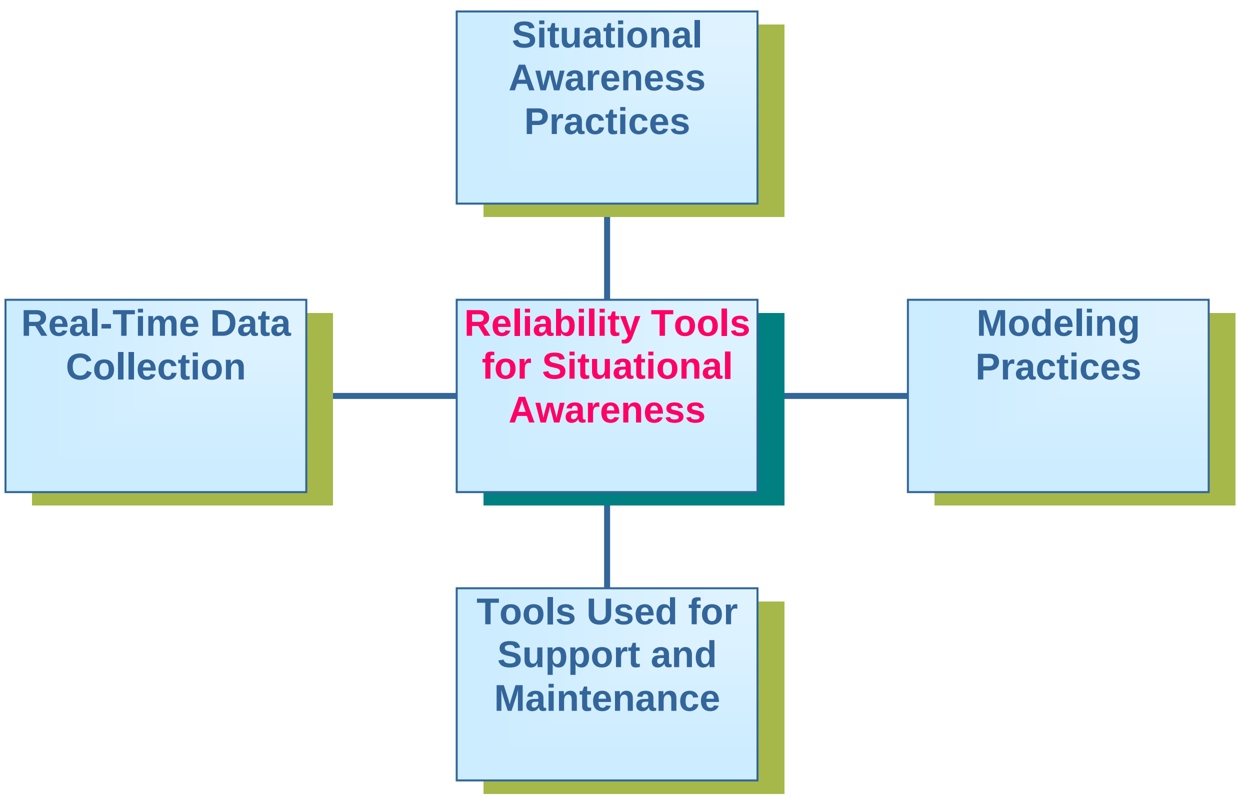

Figure 1. Real-Time Tools and Supporting Practices and Processes.

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.

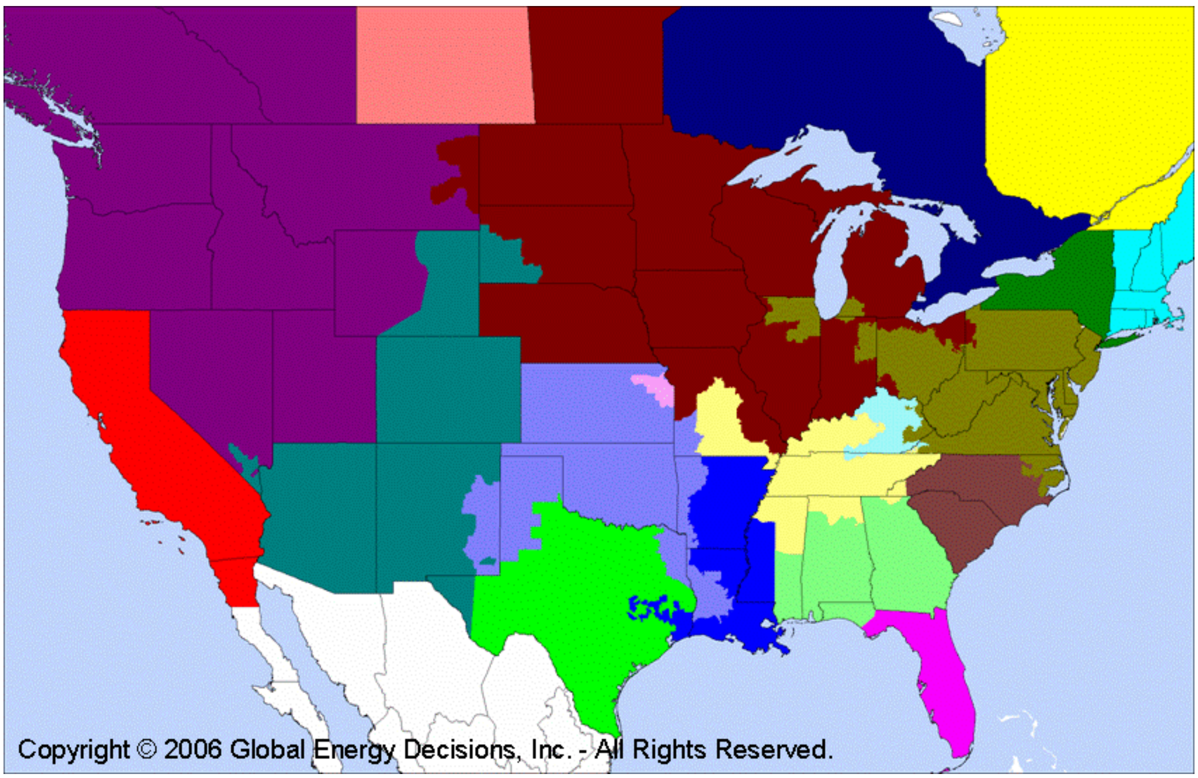

Figure 1 – Footprint of RCs that participated in the Real-Time Tools Survey

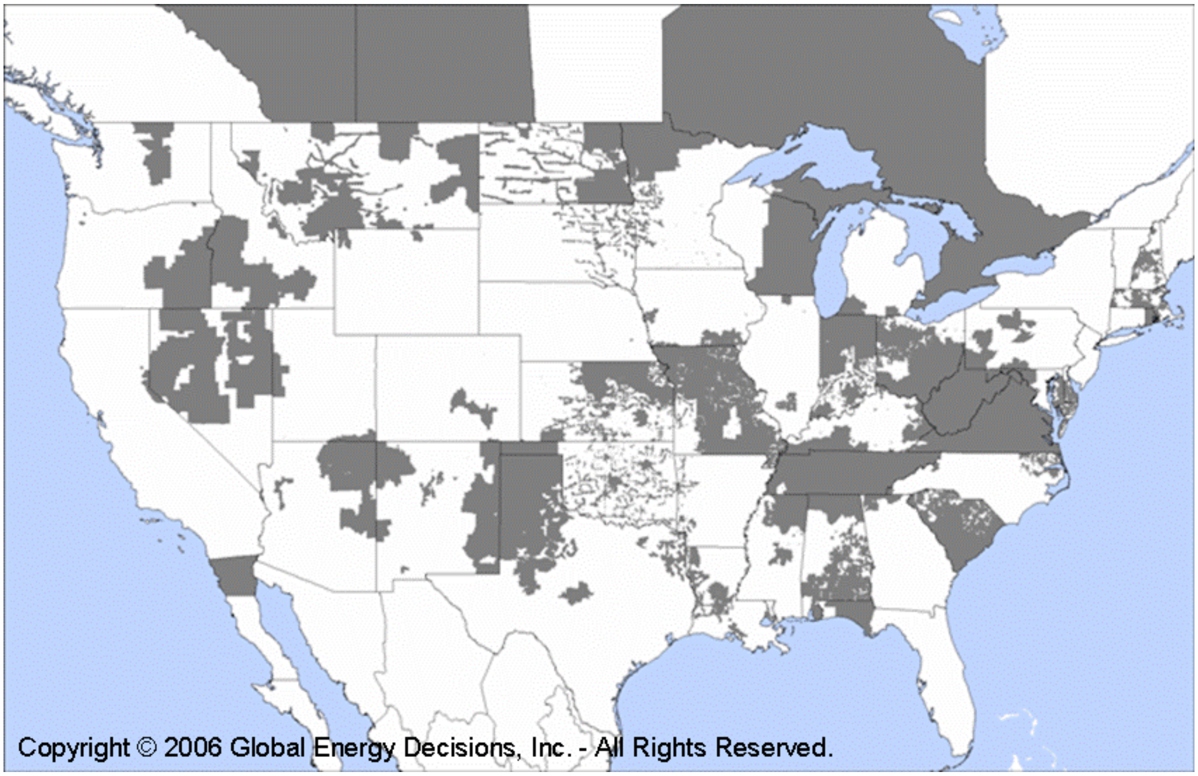

Figure 2 – Footprint of TOPs and BAs (that are not also RCs) that participated in the Real-Time Tools Survey

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).

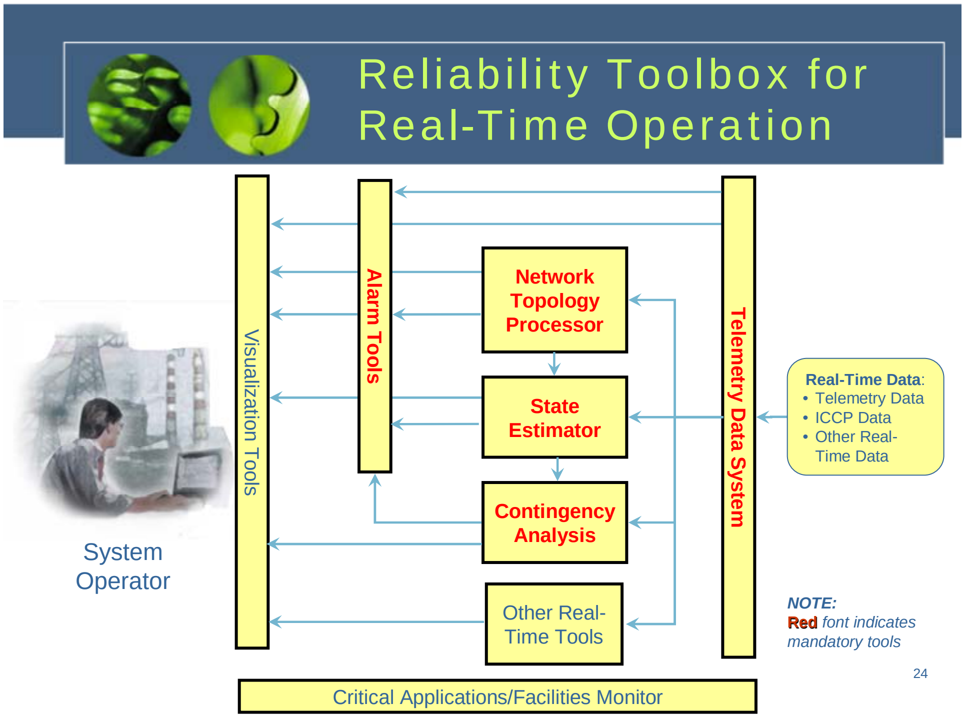

Figure 4 – Reliability Toolbox

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.

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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:

[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:

[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.

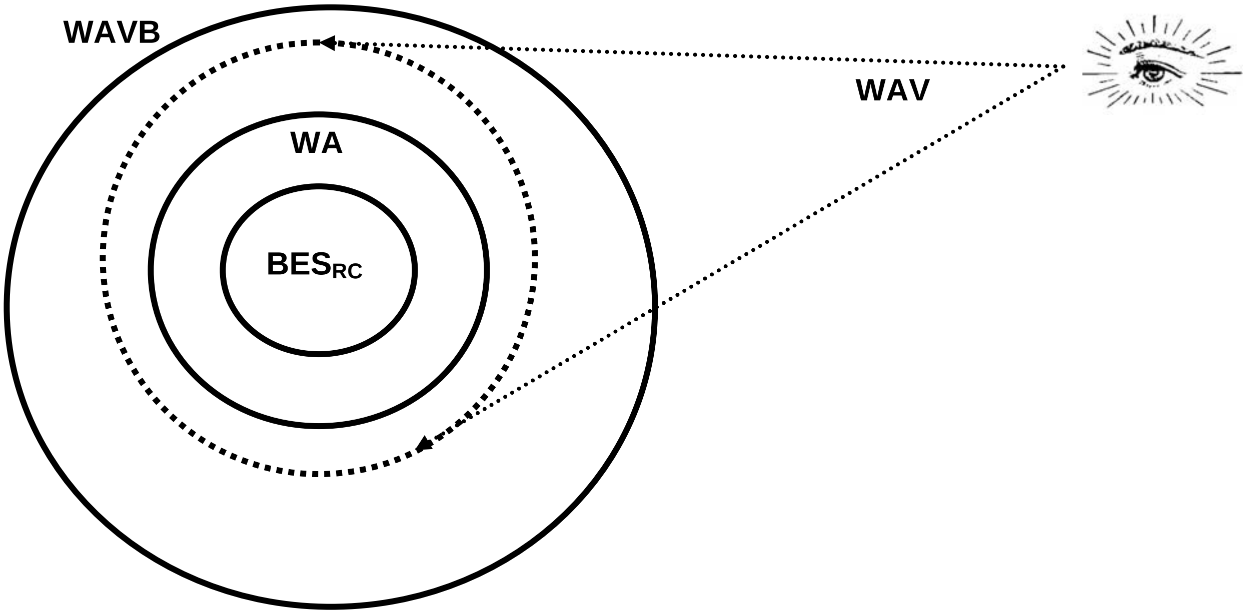
The wide-area-view boundary shall include the wide area plus the bulk electric elements in adjacent areas that are collectively needed to ensure accurate analyses of SOLs and IROLs in the wide area. Call the wide-area-view boundary WAVB and this set of bulk electric system elements the secondary BES_{Adj}.

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:

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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.