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Perspectives on Real-Time Grid Operating Technologies to Manage Reliability in the Western Interconnection

Eric Whitely, Alan G. Isenmonger, Joseph H. Eto

Environmental Energy Technologies Division

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Principal Authors:

Eric Whitely,¹ Alan G. Isenmonger,¹ Joseph H. Eto²

¹Grid Subject Matter Experts

1831 Iron Point Rd, Suite #140, Folsom CA 95630

²Lawrence Berkeley National Laboratory,

1 Cyclotron Road, MS 90R4000, Berkeley CA 94720-8136

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Acronyms and Abbreviations

ARRA	American Recovery and Reinvestment Act of 2009
BA	balancing authority
CAISO	California Independent System Operator
EMS	energy management system
EOSA	enhanced operator situational awareness
FERC	Federal Energy Regulatory Commission
GOP	generation operator
LSE	load-serving entity
NERC	North American Electric Reliability Corporation
PMA	Power Marketing Administration
RAS	remedial action scheme
RC	reliability coordinator
RTBPTF	Real-time Tools Best Practices Task Force
RTCA	real-time contingency analysis
SCADA	supervisory control and data acquisition
TO	transmission owner
TOP	transmission operator
VoLL	value of lost load
WECC	Western Electricity Coordinating Council
WISP	Western Interconnection Synchrophasor Program

Executive Summary

Although the initiating events differed, the blackouts that took place on September 8, 2011 in Arizona-Southern California-Northern Baja, Mexico and on August 14, 2003 in the Northeast United States and Canada had common underlying causes related to deficiencies in grid planning and operation. This conclusion comes from a study of the two events by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) (FERC and NERC 2012).¹ The study found that, during the eight years between these two blackouts, the recommendations for real-time grid operation and management that resulted from investigations into the 2003 blackout have not been put into routine practice.

The focus of this report is to understand why those recommendations have not yet been implemented universally and how state utility regulators, the governing boards of consumer-owned utilities, and the leadership of Power Marketing Administrations (PMAs) can help ensure implementation of these recommendations going forward. This topic is particularly timely for these bodies to address as the nation and states implement policies that are changing the electricity generation resource mix. As a result of these changes, the reliability of the high-voltage transmission grid will increasingly depend on pro-active planning and operation, including adoption of new technologies; a reliable grid is essential to the success of these policies.

This study is based on interviews with grid operating and engineering staff. It provides basic information on real-time grid operations, policies, and current practices in the Western Interconnection and identifies based on the interviews, specific areas where improvements to current practices may be warranted. The report also highlights exemplary practices and promising approaches that were identified through the interview process.

We focus on five real-time practices, tools, and technologies:

- **Network Model.** An electrical representation of all grid elements (transmission facilities), resources (generation facilities), and loads, both internal and external to a company's transmission system, that can affect the reliability of that transmission system.
- **Outage Management.** Processes for coordinating, among grid participants, planned outages of grid facilities (including protection systems and remedial action schemes).
- **Next-Day Studies.** Analyses that rely on a network model to examine how a range of possible unplanned events (contingencies) might affect reliability through the course of expected future (next-day) grid operating conditions.
- **Real-Time Situational Awareness Tools.** A suite of software tools (primarily, a state estimator and a real-time contingency analysis/dispatcher's load flow, using updated network model/topology), that support systems for communicating information on the current state of the power system (including alarms when thresholds are exceeded) and on how the power system might be affected by unplanned events to operators and that are

¹ Available at: <http://www.wecc.biz/About/sept8/Documents/FERC%20NERC%20Joint%20Report%20Arizona-Southern%20California%20Outages%20on%20September%208,%202011.pdf>

updated and re-run continuously throughout the operating day with current information on the status of grid facilities.

- **Advanced Grid Monitoring Technologies.** A class of grid monitoring technologies that augment current supervisory control and data acquisition (SCADA) monitoring by providing more granular (i.e., very high time-resolution), time-synchronized information on grid conditions—referred to generically as “synchrophasors.”²

We focus on management policies and practices for which NERC’s reliability standards are foundational.³ Compliance with these standards is mandatory and therefore is a part of everything an entity with reliability responsibilities is doing. In conjunction with compliance with standards, widespread, shared institutional and management commitment to strong or exemplary operational practices is urgently needed. Based on the interviews we conducted, it appears that these practices are not implemented consistently across the interconnection because of lack of management policies and engagement, including resources, which prioritize and reinforce consistent pursuit of these practices.

Key findings from the interviews include:

- **Network Model:** Information on conditions relevant to the grid currently under study is sometimes not complete. Missing or inadequate representations include: (1) facilities in neighboring grids; and (2) lower-voltage facilities within the grid under study.
- **Outage Management:** The approval processes for planned outages are hampered and sometimes compromised when information on planned outage of grid facilities is not shared in a timely manner or is difficult to interpret.
- **Next-Day Studies:** The quality and usefulness of next-day studies are sometimes compromised by (1) insufficient staff resources dedicated to preparation and review of the studies; (2) reliance on an inaccurate network model; and (3) inadequate information on expected grid operating conditions (e.g., lack of information on planned outages).

Inadequate sharing of next-day studies and use of compromised next-day studies can result in operators setting inaccurate operational limits (if the studies are wrong, the limits are wrong) or not having enough time to assess risk and take advance steps to resolve potential problems. This increases risk because problems must then be addressed during day-of, real-time operations when there may be fewer options for resolution, and resolution may be more complicated because of the emergence of other, unforeseen conditions.

- **Real-Time Situational Awareness Tools:** Operators sometimes do not rely on these tools because of a belief that the results of the tools do not provide useful guidance. The reasons for doubting the tools’ results include: (1) known inaccuracies in the underlying network model (notably, inadequate modeling of remedial action schemes); (2) incorrect

² As a result of American Recovery and Reinvestment Act of 2009 funding, WECC will soon have nearly 700 networked devices installed across the west, sending data in real time to WECC. WECC will use the data to drive common, interconnection-wide applications and will also make the data available to all WECC reliability entities.

³ We stress that this study is not an investigation of (and therefore reaches no conclusions regarding) firms’ compliance with reliability standards.

representation of network topology (due in some cases to inadequate information on current outages and the status of non-telemetered switches); and (3) lack of or difficulties in obtaining real-time data on current conditions in neighboring grids.

- **Advanced Grid Monitoring Technologies:** The value of synchrophasors is widely recognized for helping operators identify and respond to known grid problems (e.g., interconnection-wide grid oscillations) that have caused large blackouts in the past (e.g., the 1996 west-coast blackouts). However, tools utilizing synchrophasors are in the very early stages of deployment, and operators have not yet had the training or experience necessary to use these tools with confidence. In particular, operating guidelines have not yet been fully codified for directing the actions that should be taken in response to conditions detected by the tools.

To address these issues we have also identified the following examples of exemplary practices that we recommend for consideration for broader adoption:

- **Network Model:** Performance metrics and continuous processes to ensure the adequacy and accuracy of the network model, including: agreements with neighboring utilities for periodic updates and internal procedures for maintaining the network model, which should entail periodic review and validation to ensure the model's adequacy.

Reliance on WECC-led efforts to make updated high-level network models routinely available to grid operators.

- **Outage Management:** Consistent reliance on agreed upon naming conventions for all grid facilities, used by all who must provide or need to receive this information.

Agreed-upon deadlines (greater than one day in advance whenever feasible) for sharing information on planned outages, and agreed-upon processes for coordinating actions (for both approving and denying planned outages).

- **Next-Day Studies:** Performance metrics that assess the quality of next-day studies (including performing studies with a wider geographic scope), and management incentives that reward targeted levels of performance.

Mutually agreed-upon quality assurance requirements for the preparation of next-day studies (tied to the targeted levels of performance above) and schedules for exchange, review, and joint discussion of next-day studies.

- **Real-Time Situational Awareness Tools:** Mutually agreed-upon modeling procedures for the remedial action schemes in the Western Interconnection; reliance on real-time contingency analysis performance metrics that assess whether contingencies that occur are correctly identified, as well as the accuracy of the analysis of these contingencies; and greater reliance on newly agreed-upon arrangements for the efficient sharing of real-time operating data.⁴

⁴ The recently agreed-upon WECC Universal Data Sharing agreement is expected to help resolve the issue of data sharing among grid operators, although disagreements could remain that could affect the efficacy of information sharing.

- ***Advanced Grid Monitoring Technologies:*** Exemplary practices are in their infancy. Accordingly, we emphasize the importance of research, development, and demonstration to support adoption of production-grade, advanced applications operated by experienced personnel who are backed by operating guidelines, ongoing training, and standards guiding use of the tools.

The information in this report is intended to support the review of current practices by state utility regulators, the governing boards of consumer-owned utilities, and the leadership of PMAs, and to provide guidance and support for improvements where they are deemed appropriate. These bodies play an irreplaceable role in communicating expectations for the reliable operation of the grid to the firms they regulate or oversee as well as in enforcing these expectations; thus, they have unique influence over firms' priorities with regard to reliability.

1. Introduction

A number of reports analyzed the issues that led to the Arizona–Southern California blackout on September 8, 2011 as well as the previous, larger outage on August 14, 2003 in the Northeast United States and Canada. Analysis of the 2011 event makes clear that many of the issues that initiated the 2003 blackout—in particular the lack of situational awareness that caused it to be such a severe event—remain.

Many entities in the Western Interconnection have adopted, as part of normal operations, the best practices recommended in the wake of the 2003 blackout. However, the September 8, 2011 outage reveals that other entities in the Western Interconnection have not incorporated those best practices into their daily operations.

This study is meant to inform state utility regulators, the governing boards of consumer-owned utilities, and the leadership of Power Marketing Administrations (PMAs) regarding basic expectations of tools and business practices to ensure grid reliability. Our intent is to frame the issues and findings to assist these bodies in working with their utilities on consideration and where appropriate the adoption of exemplary practices.

In an interconnected grid, a single “weak link” can have a large impact on others. The 2011 outage offers these bodies an opportunity to establish expectations regarding grid operational practices and systems to ensure that there are no weak links in the interconnection, and to follow up and verify that those expectations regarding practices to ensure reliability are met.

This study is composed of eight sections following this introduction:

In Section 2, we describe the role and importance of real-time operations for ensuring grid reliability. We then provide basic information on real-time operational practices, including the information systems and software tools that support them. Finally, we describe the interview process used for this study, including the types of firms that were interviewed, how the interviews were conducted, and caveats that the reader must bear in mind when reviewing our findings.

In Sections 3–7, we present our findings, organized around five inter-related topics:

- Accuracy and upkeep of the network model
- Coordination processes for outage management
- Quality and sharing of next-day studies
- Use of real-time situational awareness tools
- Introduction of advanced grid monitoring technologies

These topics are presented using a uniform structure. For each topic, we first provide a brief description, referring to the basic information provided in Section 2 and including a discussion of

the topic's significance for reliability. Next, we review what interviewees told us about their current practices; where appropriate, we identify exemplary practices.

In Section 8, we summarize our findings and recommended next steps.

Several appendices follow the list of references:

- Appendix A provides a list of questions on aspects of real-time operations that can be referred to in discussing current practices with firms.
- Appendix B provides background information on the reliability roles and responsibilities of firms within the Western Electricity Coordinating Council (WECC).
- Appendix C summarizes the literature we reviewed in preparing this report.

2. Focus, Scope, and Conduct of this Study

In this section, we describe the role and importance of real-time operations for grid reliability. We then provide basic information on real-time operational practices, including the information systems and software tools that support them. Next, we describe the process we used to interview firms for this study, including the types of firms that were interviewed, how the interviews were conducted, and, importantly, the caveats that must be kept in mind in reviewing the findings we present. Finally, we discuss the presentation of findings that follows in the subsequent five sections.

2.1 The Role and Importance of Real-Time Operations

This study focuses on real-time operations. Other activities, such as building new transmission facilities, interconnecting new sources of generation, and creating demand management capabilities, are all important for reliability but take place over lengthier time scales than are relevant for the activities that are the focus of this report.

The role and importance of real-time operations is best exemplified by the following quote from the August 14, 2003 Blackout report (U.S.–Canada Power System Outage Task Force 2004):

It is a basic principle of reliability management that “operators must operate the system they have in front of them”—unconditionally. The system must be operated at all times to withstand any single contingency and yet be ready within 30 minutes for the next contingency. If a facility is lost unexpectedly, the system operators must determine whether to make operational changes, including adjusting generator outputs, curtailing electricity transactions, taking transmission elements out of service or restoring them, and if necessary, shedding interruptible and firm customer load—i.e., cutting some customers off temporarily, and in the right locations, to reduce electricity demand to a level that matches what the system is then able to deliver safely.

In its most basic form, operating the power system reliably in real time involves having knowledge of, along with the means to change, the current state of at least those elements of power system for which an entity is responsible. Telemetry and monitoring tools that provide real-time information on the status or operating state of these power system elements are fundamental to providing this required knowledge. If the tools detect that an element is operating outside safe limits, the operator must take action to restore operation to within these limits.

In addition, because threats to reliability can propagate at essentially the speed of light across an entire interconnection, reliability management necessitates advance understanding of and preparations to ensure reliable system operation when things go wrong. Developing this understanding requires both analytical tools and accurate information on current and expected future grid conditions. Analytical tools are required to conduct advance “what if” analysis of the things that could go wrong. Accurate information on grid conditions is required so that these tools base their predictions on a correct model of how the grid will respond to these what-if conditions. If the models are wrong, then the operating limits determined based on these tools

will also be wrong, and operators will not have an accurate picture of the power system in front of them.

2.2 Real-Time Operational Practices and Tools

Following the August 14, 2003 blackout, the North American Electric Reliability Corporation (NERC) established a task force to make recommendations on best practices for real-time tools. The real-time tools best practices task force (RTBPTF) report defined “situational awareness”⁵ and identified a suite of tools and practices required to achieve this goal (NERC 2008). The findings from the task force report formed the basis for the topics we used to structure and guide the interviews that we conducted for the current study.

For the purposes of its analysis, the RTBPTF defined situational awareness as follows:

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.

For this report, we drew from the findings and recommendations of the RTBPTF and other sources (FERC and NERC 2012; WECC 2013) to identify the following five topic areas, which we used to organize the information obtained through our interviews:

- **Network Model.** An electrical representation of all grid elements (transmission facilities), resources (generation facilities), and loads, both internal and external to a company’s transmission system, that can affect the reliability of that transmission system.
- **Outage Management.** Processes for coordinating, among grid participants, the planned outages of grid facilities (including protection systems and remedial action schemes).
- **Next-Day Studies.** Analyses that rely on a network model to examine how a range of possible unplanned events (contingencies) might affect reliability through the course of expected future (next-day) grid operating conditions.
- **Real-Time Situational Awareness Tools.** A suite of software tools (primarily, a state estimator and a real-time contingency analysis/dispatcher’s load flow, using an updated network model/topology), that support systems for communicating information on the current state of the power system (including alarms when thresholds are exceeded) and on how the power system might be affected by unplanned events to operators and that are updated and re-run continuously throughout the operating day with current information on the status of grid facilities.

⁵ In this study, we use the term “situational awareness” as defined by the NERC RTTBPTF: a state of knowledge that it recommends that grid operators possess to operate the grid reliably in real time. We use the term as “real-time situational awareness tools” to refer to a suite of software tools used by operators to gain this state of knowledge.

- ***Advanced Grid Monitoring Technologies.*** A class of grid monitoring technologies that augment current supervisory control and data acquisition (SCADA)-base monitoring by providing more granular (i.e., very high time-resolution) and time-synchronized information on grid conditions—referred to generically as “synchrophasors.”⁶

2.3 Interview Process and Caveats

The project team interviewed staff at 11 firms to develop the findings presented in this report. By and large, the individuals we interviewed were grid operators or operating engineers, managers, and directors of engineering and operations. The focus of this study was to understand what operators deemed used and useful from their perspectives. From the engineering perspectives, we focused on what gaps they felt were in the current abilities to support analytical tools, situational awareness and business processes such as model updates, outage management and next-day study processes.

All of the firms are members of WECC, which is the regional entity under NERC that is responsible for maintaining reliability in the Western Interconnection.⁷ Table 1 lists the firms and reliability responsibilities they have within WECC.⁸ See Table B-1 for detailed definitions of each entity designation.

The firms we interviewed, taken together, are not a statistically representative sample of firms within the Western Interconnection. Therefore, the information we gathered on current practices is, at best, illustrative. Although we believe that our findings may be representative of the practices of firms we did not interview, we do not draw any conclusions that hinge on such a determination. Instead, we abstract from our findings to develop questions—summarized in Appendix A—that can be used to explore these topics with other firms.

The staff members we interviewed at each firm provided us their assessments with the understanding that the information would not be attributed. We have respected these agreements and have not sought formal, independent verification of the information provided to us. Consequently, we make no claims regarding the veracity of information provided to us or its representativeness of the practices of individual firms. The questions in Appendix A may be useful to others in seeking independent corroboration of the information we gathered.

⁶ As a result of American Recovery and Reinvestment Act of 2009 funding, WECC will soon have more than 800 networked devices installed across the West which will send real-time data to WECC. WECC will use the data to drive common, interconnection-wide applications and will also make the data available to all WECC reliability entities.

⁷ The Western Interconnection covers nearly 1.8 million square miles and includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 contiguous western U.S. states in between.

⁸ Appendix C provides more information on the roles and responsibilities of these designations and an overview of the firms with the Western Interconnection that share these responsibilities.

Table 1. Entities Interviewed

Entity Name	Entity Designation
California Independent System Operator	BA/TOP
Balancing Area of Northern California	BA
Arizona Public Service	BA and TO/TOP
Platte River Power	TO/TOP
Southern California Edison	LSE; TO/TOP
Alberta Electric System Operator	BA
Brookfield Energy	GOP
BrightSource	GOP
Western Electricity Coordinating Council Reliability Coordinator	RC
Northwestern	BA and TO/TOP
Bonneville Power Administration	BA and TO/TOP

BA – balancing authority; TO – transmission owner; TOP – transmission operator; LSE – load-serving entity; GOP – generation operator; RC – reliability coordinator.

Some entities, especially those with subsidiaries and affiliates, have multiple designations, so this list is illustrative and not exhaustive. To look up the specific registrations for any NERC-registered entity please visit: <http://www.nerc.com/page.php?cid=3%7C25>

Finally, we wish to state categorically that our interviews did not seek—nor do the authors have authority to reach—conclusions regarding compliance with reliability standards. That is not the purpose of this study.

Instead, the purpose of this study is to assess what the interviewees told us about current practices and, relying on other interviews or reports on this topic (see Appendix C), to identify areas where improvement may be warranted. Based on the exemplary practices that we identified, we conclude that current practices sometimes fall short of those examples, and therefore can be improved. However, whether to make such an improvement is a management decision, and we recognize that all the factors that go into making such decisions are beyond the scope of this report. For example, at the time this study was prepared, monetary fines that are expected to follow from the findings of the September 8, 2011 Arizona–Southwest California blackout investigation have not been assessed. The magnitude of those fines will provide utility management a direct measure of the value of (i.e., the costs they might avoid incurring by) adopting improved practices and technologies.

3. The Accuracy and Upkeep of the Network Model

The network model is an electrical representation of all grid elements (transmission facilities), resources (generation facilities), and loads, both internal and external to a company's transmission system, that can affect that transmission system's reliability.

3.1 Importance for Reliability

The network model provides the basis for routine studies (on multiple time scales: seasonal, weekly, next-day, day-of) that inform grid planning and operating decisions. An inaccurate or inadequately detailed network model undermines the accuracy and usefulness of the studies that it supports.

Network models are time consuming for organizations to maintain. Additions, deletions, and changes to field equipment affect the accuracy and results of the network model and therefore must be consistently incorporated into the model. Modeling and data issues are generally not solvable in real time. They have to be addressed in advance, by means of an ongoing model update process that is coordinated across the interconnection. If network models are not accurate, operators become mistrustful of the models' results and also mistrust other tools that depend on an accurate network model (e.g., an inaccurate network model may cause the state estimator to fail to produce a solution, which in turn will render the contingency analysis tool un-usable).

Once the model is created, it must be installed into the real-time Energy Management System (EMS). The analytical applications that are relied upon by operators are then run on the installed model.

One key issue that limits the accuracy of the network model once it has been installed into the EMS is that many switching devices included in a well-detailed model do not have telemetry to indicate when they are closed or open. Once a model is incorporated into the EMS, keeping network switching (known as "topology") updated is an ongoing task. Unless operations identifies the current status of switches in real time (i.e., opens or closes the switches in the real-time system indication), the model assumes that a switch is closed. The results of the model are inaccurate when it treats open switches as closed.⁹

Most operating entities currently have operational network models for their own areas of responsibility plus some detail regarding adjacent systems that influence their flows because this information is necessary to correctly depict the impact of events that occur in neighboring systems on the local system. One of the major issues identified in the Arizona–Southern California outage report was lack of accurate models and resulting lack of use of the tools that depend on those models. In particular, the report determined the electrical networks outside of an entity's area of responsibility were poorly covered in models, and, in some cases, lower-voltage

⁹ One reviewer expressed the opinion that it would be desirable to develop an automatic or semi-automatic tool to identify and correct topology errors, including the state of non-telemetered switches.

networks within the area of responsibility were also poorly covered even though these networks could influence the bulk power system.¹⁰

3.2 Findings from Interviews

In the interviews we conducted, two main impediments to adopting tools such as state estimators and real-time contingency analysis (RTCA) were identified: the difficulty of keeping models current and the difficulty of having operations staff review and perform upkeep of those models in real time. Among the challenges of keeping models current is obtaining information within a firm (e.g., planning and construction processes often do not include procedures for updating real-time models) and obtaining information from neighboring transmission owners (because, as noted above, network model tools need to “solve” for a greater area than a single transmission system).

Several entities whose representatives we interviewed (e.g., the larger, market-based companies and some larger transmission-owner companies) have well-established procedures for updating models and real-time practices for accurately documenting topology and thus ensuring that the results of the model are valued by operations staff. These practices allow those companies to effectively use these analytical tools to assist operations.

For example, the California Independent System Operation (CAISO) does not allow facilities to be energized until their network models are updated (typically once a quarter). However, other organizations have more flexible approaches.

Keeping models current requires a dedicated staff and management placing a priority on this activity. Several issues were mentioned in interviews as impediments to keeping models up to date.

One was the conflict between trying to get a project or grid change on line and the need to wait for information to be incorporated into network models during scheduled operational model-build cycles.¹¹ An asset owner can face severe penalties if projects are late. The result can be a last-minute scramble to ensure that models are updated or an agreement by the management of an entity to grant an exception to requirements for updating models in order to avoid expensive penalties. In addition to internal models sometimes not being updated prior to projects going on line, adjacent entities are not always given updated information prior to grid changes taking effect.

An example from one large entity that we interviewed was a project that was to be brought on line but was held back because the data reflecting the new project were not in the network model, and the cycle time for updating the model was several months. Delay of the project launch would

¹⁰ A related issue identified by one of the report reviewers is that there are inaccuracies in the load models used to conduct dynamic simulation studies. These inaccuracies affect the determination of seasonal and limits that are studied using dynamic simulation tools. However, they do not directly affect real-time operations, which rely primarily on steady-state not dynamic simulation tools.

¹¹ Network models are generally released into production every two to three months. Thus, timing of the installation of new generation or transmission equipment must be coordinated with the network model-build cycle to ensure that, when the new facility is cleared for operation, it is already represented in the models. When new facilities are not represented in models, reliability issues—as well as market issues—result.

have resulted in large fines specified in the power-purchase agreement. As a result, the management granted an exception to the requirement to update the model prior to the project launch. However, as a result, real-time analysis that depends on an up-to-date model was incorrect until the update in the network model was finally made. Even within a single organization, conflict between planning and construction departments results when priority is not given to ensuring that details of new projects are updated in network models prior to the projects being energized. Resolving this issue requires that management place priority on—and adopt—business processes that respect the accuracy of real-time models and the results of the real-time analysis tools.

Interviewees mentioned lack of communication, lack of coordination, and staffing issues as key impediments to accurate upkeep of models. The size and culture of the staff of each entity that is responsible for updating network information play an important role in the continual upkeep of real-time models. Several interviewees discussed the need for executive support to ensure accuracy in real-time tools.

Many times planning and operational groups within a company are not fully coordinated with one another so that they share data. Construction, protection, and program facilitators may be focused on schedules and issues other than communication circuits, remote terminal units, and information in models; as a result, these elements are often addressed very late in the process of bringing a new facility on line. In addition, sharing of models among adjacent companies is sometimes an afterthought rather than a critical process.

We noted, as exemplary, practices we learned about in companies that summarize the results from their analytical tools in the form of metrics and scorecards. These practices signal that accuracy is important and that engineers and operators should prioritize analysis of real-time grid conditions.

In addition, we also note as exemplary current efforts by the WECC Reliability Coordinator (RC) to help entities share data from their models through the multi-use WECCRC.org website functions. This is still a developing set of services and systems, but WECC plans to share data for updating models through a central site. That site will give all entities access to detailed model information and allow them to verify that network model information is accurate.

3.3 Summary

We find that information on grid conditions is sometimes not current or complete. Information gaps include missing or inadequate representation of (1) facilities in neighboring grids; and (2) lower-voltage facilities within the grid under study. The lack of accurate information compromises operators' ability to make accurate decisions in real time.

Exemplary Practices for Consideration for Broader Adoption:

- Establishing performance metrics and continuous processes for ensuring the adequacy and accuracy of the network model, including agreements with neighboring utilities for

periodic updates and internal procedures for maintaining the network model; those procedures should include periodic reviews to ensure the model's adequacy.

- Reliance on WECC-led efforts to make updated high-level network models routinely available to grid operators.

4. Coordination Processes for Outage Management

Outage management refers to processes for coordinating, among grid participants, planned outages of grid facilities (including protection systems and remedial action schemes)

4.1 Importance for Reliability

The planned outage (or unavailability) of grid facilities directly affects the options available to grid operators to position (dispatch) the remaining available (non-outaged) grid facilities to ensure that the grid can withstand and recover from unplanned events. Timely outage information allows operators to study the combined impact of outages on neighboring systems on their own system.

Bulk power system equipment maintenance typically involves de-energizing the equipment and keeping it out of service until maintenance activities are complete. Determining the timing of equipment maintenance requires understanding the impact of removing the equipment from service, especially what would happen if a contingency or unforeseen outage were to occur while the equipment is out of service. Having equipment out of service is among the highest-risk factors in management of an interconnected electrical network and is the reason for real-time studies of risk to the grid. Outages can vary from long-range, planned events (for example, related to major construction that is planned years in advance) to short-term forced events (for example, when failed equipment is taken out of service within minutes). In either case, coordination of outages and sharing of outage data among electrical entities is critical to understanding the risk posed to the grid, and to ensuring that adjacent entities don't unknowingly take equipment out of service at the same time and thus exacerbate risk.

The exchange of outage management information can take place using three possible procedures that depend on the relationship between the transmission owner and operator or the location of the outage:

1. *Transmission Owner is different from Transmission Operator (TOP).* When the transmission owner is different from the transmission operator, coordination between the owner and operator regarding outages must be complete, with outages fully specified. This procedure is common in organized markets.
2. *Transmission Owner is affiliated with Transmission Operator.* When the transmission owner is the same as the transmission operator (e.g., within a given TOP), the data exchange is wholly within the company although between different parts of that company.
3. *Outages are external to Transmission Operator.* A TOP needs data from an adjoining authority when an outage on the adjoining authority's electrically connected equipment affects the TOP's internal equipment. In this situation, the effect of transmission outages outside the system could be mitigated either by transmission changes by the TOP or generation changes internal to the balancing authority (BA). Outages require regional assessment and coordination to prevent unintended consequences. A regional approach only works when there is appropriate communication among neighboring TOPs and BAs along with appropriate RC oversight.

4.2 Findings from Interviews

There is no uniform, accepted methodology for sharing outage information. The mandatory NERC standard regarding sharing outage data (TOP-003-1) only states that notification must be given one day in advance. Most entities give outage notifications approximately three to seven days in advance. There is a WECC Outage Working Group working to develop regional standards, but as yet these standards have not been developed beyond a few best practice examples, nor is it expected that the standards would be a requirement even if they are implemented.

A number of adjacent entities have developed cooperative practices for advanced notification and sharing of study results. Some of these practices are exemplary. For example, the Northwest Power Pool gives notification 45 days in advance, which helps all entities in their region manage risk. In addition, the WECC RC posts the coordinated outage system tool for sharing outages that other entities submit, as well as a day-ahead study tool where all entities can share study results. We deem both of these practices as exemplary.

In spite of such exemplary practices, we also found practices confirming that not every transmission owner/operator shares data in a timely and efficient manner with adjacent interconnected entities and with the relevant BA and RC.

In the extreme, interviewees reported having to scramble to “interpret” outage information in a timely manner (in one case, operators had to work until 0400 in the morning of the day when an outage was to take place at 0600). This approach was recognized as introducing risk, and operators expressed frustration at learning of issues at the last minute, just prior to outages.

Another issue that affects coordination is the lack of shared terminology or formats for presenting data. Interviewees pointed to the lack of reliance on previously agreed-upon common names for equipment as well as a lack of discrete data fields for populating table-oriented data. These inconsistencies in terminology and format cause operators to have to interpret the duration of an outage, the components involved, etc. when notification is received. If their interpretation is wrong or the input format creates errors, their ability to accurately assess grid conditions is affected. Interviewees described many “near misses” as a result of these types of problems.

Some interviewees used the term “mavericks” to describe the firms exhibiting the above practices. Interviews with companies who have resolved these issues, or who are small enough to know adjoining entities’ systems well, described a much more “coordinated” set of practices.

4.3 Summary

We find that the approval processes for planned outages are hampered and sometimes compromised when information on planned outage of grid facilities is not shared in a timely manner or is difficult to interpret.

Exemplary Practices for Consideration for Broader Adoption:

- Consistent reliance on agreed-upon naming conventions for all grid facilities among all those who must provide or need to receive this information and a common format to deliver the outage data to aid automated tasks.
- Agreed-upon deadlines (greater than one day in advance whenever feasible) for sharing information on planned outages and agreed-upon processes for coordinating actions (for both approving and denying planned outages).

5. The Quality and Sharing of Next-Day Studies

Next-day studies rely on a network model to examine how a range of possible unplanned events (contingencies) might affect reliability during the course of expected future (next-day) grid operating conditions.

5.1 Importance for Reliability

Next-day studies inform adjustments to scheduling of grid facilities (including the approval or denial of planned outages) to ensure that the grid can withstand and recover from unplanned events. Sharing of next-day studies enables grid operators to consider how expected conditions on neighboring systems might affect their own operations.

NERC standards direct that next-day studies must be conducted by each TOP, BA, and RC. “Next-day” means, as the name suggests, that, each day, a responsible entity must, each day, conduct an analysis (typically an engineering function) of its system to ensure that system operating limits are known for the conditions expected on the following day. The goal is to ensure that the system can be operated reliably (i.e., with enough generation and transmission that the grid can withstand unplanned outages).

A next-day study typically involves running an off-line model that simulates operations at the time of the next day’s expected system peak load, taking into account all known outages. Information regarding outages known or expected on the following day is usually received before 12:00 noon of the preceding day. The study engineer then uses the model to “stress” the system and find any weak links. The results of this study help identify contingencies (scenarios), whose impacts must be addressed. The results from a next-day study may be used to halt (deny) planned outages and/or to request additional generation or re-dispatch planned generation.

5.2 Findings from Interviews

Our interviews revealed several issues with this daily task, which are of concern for the interconnection overall. These included:

- Staff assigned to conduct next-day studies are sometimes pulled off this assignment to complete other projects.
- The daily study is not reviewed for accuracy or value. This was reported by several interviewees. This indicates that, for some, next-day studies are viewed as simply a task to be checked off rather than as a valuable tool for operations.
- Next-day studies may be run with assumptions or best engineering judgments rather than correct inputs or outage information. Interviewees who had expressed problems in obtaining clearly stated outage information in a timely manner (see Section 4 above) also expressed the concern that lack of clear and timely information affected the accuracy of their next-day studies.

Many interviewees expressed that a 24/7 engineering position is key to ensuring that studies are up to date and accurately reflect changes in grid conditions. Real-time outage changes, grid events, etc. can quickly overwhelm an operator's ability to assess regional status or the impact of neighboring entities. Many larger entities and the WECC RC are determined to establish permanent engineering positions in their control rooms.

Disagreements over study results are sometimes not resolved in advance and must be addressed during the operating day. Disputes sometimes arise because outages can involve financial penalties, and outage effects can spill over to adjacent entities, modifying their purchases of generation, fuel supplies, etc. The disputes sometimes take the form of disagreements regarding the conduct or interpretation of a neighbor's next-day study results. There is a hierarchy for resolution of these disputes that ends with decisions by the WECC RC.

The practices reported to us that we deemed exemplary included: Studies that started seven days ahead, with new validated outages added each day. This allows operators to coordinate outages farther in advance and without the pressure of trying to interpret information and address impacts the day before.

In addition, the WECC RC Next-Day Study process posts the results of entities' studies as well as the RC's day-ahead study on the WECCRC.org website. Sharing of studies uniformly is the beginning of improvement of grid awareness by all reliability entities but is still not used by all.

5.3 Summary

The quality and therefore the usefulness of next-day studies are sometimes compromised by (1) insufficient staff resources dedicated to preparation and review of the studies; (2) reliance on an inaccurate network model; and (3) inadequate information on expected grid operating conditions (e.g., lack of information on planned outages).

Inadequate sharing of next-day studies and/or use of compromised next-day studies may mean that operators will set inaccurate operational limits (if the studies are wrong, the limits are wrong) or not have enough time to assess risk and take advance steps to resolve potential problems. This increases risk because problems must then be addressed during day-of, real-time operations when there are fewer options for resolution than there are in advance, and resolution can be made more complicated by the emergence of other, unforeseen conditions.

Exemplary Practices for Consideration for Broader Adoption:

- Performance metrics that assess the quality of next-day studies (including performing studies with a wider geographic scope) and management incentives that reward targeted levels of performance. A key metric is one that assesses the accuracy and adequacy of next-day study findings compared to what actually happened on the operating day. When there are significant differences, analysis is conducted to identify and determine the reasons for these differences.

- Mutually agreed-upon quality-assurance requirements for the preparation of next-day studies (tied to the above metrics) and schedules for exchange, review, and joint discussion of next-day studies.

6. Use of Real-Time Situational Awareness Tools

“Real-time situational awareness tools” refers to a suite of software tools (primarily, a state estimator and a real-time contingency analysis/dispatcher’s load flow, using updated network model/topology) that support systems for communicating information on the current state of the power system (including alarms when thresholds are exceeded) and on how the power system might be affected by unplanned events to operators. These tools are updated and re-run continuously throughout the operating day with current information on the status of grid facilities.

6.1 Importance for Reliability

Situational awareness tools are essential for conducting “what-if” analysis of current grid conditions to guide real-time operating decisions and ensure that the grid can withstand and recover from unplanned events. In real time, grid conditions routinely deviate (sometimes, dramatically) from those that were assumed when next-day studies were done. Critical inputs to this suite of tools (network modeling, outage management, next-day studies) have already been covered in other sections of this report, so this section focuses on accurate and timely information on real-time conditions (real-time data) and the processes for conducting real-time studies.

Real-time data are often referred to as SCADA data. The information from major field devices, such as breakers, generators, lines, and switchyards, is captured by instruments and transmitted to an entity’s energy management system (EMS). SCADA information gives a snapshot of data every few seconds, alerting grid operators to alarms, changes, or other conditions. Operators can then run analytical tools using real-time data and an accurate network model.

The state estimator uses the network model (see Section 3) along with updated information on current network topology (see Section 4) and telemetered measurements of the current operating condition of grid elements (voltage and flow of power on a transmission line) to develop an electrically consistent representation of the current state of the grid. The state estimator “fills in” missing values for the operating condition of grid elements that are not telemetered. It also reconciles potential inconsistencies among the measurements of multiple elements when, for example, there is error in one or more measurements. Notably, however, a state estimator cannot fill in missing information regarding network topology (i.e., on the status of equipment—whether it is in or out of service or whether a non-telemetered switch is open or closed).

The real-time contingency analysis (RTCA) tool takes the representation that is produced by the state estimator and evaluates how grid conditions might evolve if one or more contingencies take place (such as the loss of a transmission line or loss of a generator). If the RTCA indicates that safe grid operating limits would be violated, the operator must take actions to re-dispatch grid resources and elements to ensure that these limits will not be violated if the contingency does, in fact, take place.

6.2 Findings from Interviews

As can be gathered from the descriptions of the inputs to real-time situational awareness tools, problems affecting the accuracy of network modeling (discussed in Sections 3 and 4), including sharing of information on outages, directly affect the usefulness of the real-time tools that depend on this information. Accordingly, we organize the results of our interviews in this section around the following aspects of operators' views on the usefulness of these tools: (1) the relevance or perceived necessity of the tools as a function of system size and operator experience; (2) the ability of the real-time analysis tools to reflect all relevant grid information; and (3) challenges to obtaining real-time data from neighbors.

The size of the entity makes a significant difference in operators' familiarity with their system and the degree of automation in system operations. This is one reason that some operators distrust one-size-fits-all policies. In the smaller balancing and transmission operation entities, there is much less automation (even to the extent of not having working EMS state estimation and RTCA type tools). Operators do not see this as a detriment because, in smaller transmission operation entities, the operators often know the system extremely well. One of our interviewees was a small transmission operations group; this group stated that, if forced, they would implement a network model and the required tools, but they didn't see much use for them. Their system is small, and the number of interactions between the transmission and generation elements are few. The operators appear quite capable of managing their system reliably because they are very familiar with the limited number of possible configurations of the grid.

The ability to maintain intimate familiarity with a system decreases as the size of the entity increases. At a certain point, operators cannot know the system intimately because it is just too big, and the number of grid permutations is too many for an individual to know in detail. In this situation, operators are forced to rely on models, procedures, and analytical tools. It is difficult to tell exactly where the transition point is between a small system manageable by knowledgeable operators and a larger system requiring modeling tools. However, it appears clear that a small balancing or transmission entity can be managed reliably by skilled operators without complex analytical tools whereas, at larger entities, operators need to augment their skills with study analysis, contingency analysis, and a variety of higher-level analytics. In the larger system, there are too many transmission elements and possible permutations for any one person to be able to think of solutions. When operators rely more on tools, some degree of granularity and specialized knowledge is lost. An experienced older work force (knowledge) being replaced by a younger more engineering-minded work force (competencies) can be a key element in the move to adopting and relying on analytical tools.¹²

The usefulness of the higher-level analytics in situational awareness tools depends on consistent maintenance and accurate, up-to-date modeling. For example, one of the issues that came up in the interviews is that the modeling of remedial action schemes (RAS) (also known as special protection) is in its infancy.¹³ As a result, if the RTCA tool does not include an RAS that the

¹² More than one reviewer also pointed out that robustness of tools is also important. Tools that are not maintained may fail to provide crucial information needed by operators at precisely the times when that information is most sought.

¹³ A remedial action scheme is an automatic set of procedures that immediately implements a control action (such as the tripping of generation or a transmission line) once a pre-identified grid operating condition is sensed. A RAS

operator knows is in operation, then the contingency list that the tool produces is incorrect. When this happens, the operator turns to direct measurements, and often to less-sophisticated information such as SCADA displays, to find information that the operator regards as more reliable. Thus, diligence in preparing models is vital, especially in larger entities that rely more heavily on higher-level analytical tools.

Another issue that came up in interviews is that protection systems are constantly changing and are not well represented in analytical tools. The Western Interconnection utilizes RAS schemes to rapidly remediate risk and ensure that transmission corridors can be fully utilized. The wide variety of RAS operations makes modeling a challenge because, for example, the status of “armed” or “ready” might not be defined consistently from one entity or system to another.

The benefits of RTCA generally seem to be appreciated across the industry, but implementation, particularly in the Western Interconnection, is patchy and imperfect. In addition, RTCA places significant resource demands on engineering staff. If modeling is done properly and the RTCA is accurate, then the information is enormously useful; however, if the modeling is imperfect, then the RTCA results are worthless and ignored. For RTCA to be useful, the data integrity requirement must be extremely high. Many organizations are not reaching the data integrity threshold at which RTCA becomes used and useful.

A recent positive development has been the implementation of the WECC-led Universal Data Sharing Agreement that allows entities to share data without asking for specific approval. The WECC RC can now share specific data from the entire interconnection with entities that have reliability management responsibilities through its tools located on the WECCRC.org portal. Exemplary practices were observed in entities that fully utilize the recently executed WECC Universal Data Sharing agreement to share their data with neighboring reliability entities.

We also heard anecdotal stories of the WECC RC contacting entities to let them know that a condition existed at a neighboring entity which affected them. This, in turn, allowed the affected entity to request real-time data so that, in the future, they could be alerted as well. Those stories have become more commonplace because of an increase in available real-time data as well as because of NERC standards.

Issues remain, however, with real-time data sharing. Our interviews revealed that although everyone agrees that sharing of real-time data is important, there is distrust about whether the data will be used for market manipulation or other competitive advantage. There are also concerns that entities’ own data will be used against them when disputes arise. Concerns were expressed regarding compliance violations and limiting the use of or sharing of data; these concerns indicate that some entities do not see the importance of automatically sharing all real-time grid operational data. Examples were reported of entities simply saying no to data requests or requiring explicit justification each time and for each data point requested.

differs from a protection system, which also operates automatically, because a RAS is designed to ensure the reliability of the grid, while a protection system is designed to prevent damage to a specific piece of equipment.

6.3 Summary

We find that operators sometimes do not rely on real-time situational awareness tools because of a perception that the results of the tools do not provide useful guidance for taking action. The reasons for this perception include: (1) known inaccuracies in the underlying network model (notably, in addition to factors identified in Section 3, inadequate modeling of RAS); (2) incorrect representation of network topology (notably, in addition to the factors identified in Section 4, the current status of non-telemetered switches); and (3) lack of or difficulty in obtaining real-time data on current conditions in neighboring grids.

Exemplary Practices for Consideration for Broader Adoption:

- Mutually agreed upon modeling standards for remedial action schemes in the Western Interconnection, reliance on RTCA performance metrics that evaluate the correct identification of contingencies and the accuracy of the analysis of contingencies that occur, and greater reliance on newly agreed-upon arrangements for efficient sharing of real-time operating data.¹⁴

¹⁴ The recently agreed-upon WECC Universal Data Sharing agreement is expected to help resolve this issue although disagreements may remain that could affect the efficacy with which information is shared.

7. The Introduction of Advanced Grid Monitoring Technologies

“Advanced grid-monitoring technologies” refers to a new class of grid-monitoring technologies that augment current SCADA-base monitoring by providing more granular (i.e., very high time-resolution) and time-synchronized information on grid conditions. These are known generically as “synchrophasors.”

7.1 Importance for Reliability

In contrast to traditional telemetry, which relies on sequential measurements of grid conditions taken every 4 to 10 seconds, synchrophasor technologies take snapshots of grid conditions 30 or more times per second. Synchrophasor technologies also attach precise time-stamps to each snapshot so that snapshots taken by different entities can be time-aligned to provide a consistent picture of grid conditions at every instance in time and across the entire interconnection.

Synchrophasor technologies enable both more granular and wide-area assessment of current grid conditions than is possible with current grid monitoring technologies. The use of the technology for real-time operations is currently limited to monitoring (which is viewed mainly as a back-up to traditional SCADA monitoring). Analysis technologies that reveal information on grid health based on these more precise measurements are still under development and have yet to mature to the point at which they are relied on by operators to make grid operating decisions. Yet, it is universally acknowledged that the information provided by these measurements far surpasses the information that is available from SCADA monitoring. A leading example in the West is information that synchrophasor technologies provide on inter-area oscillations, which were a direct cause of the 1996 blackouts on the west coast and which cannot be captured through SCADA monitoring.

7.2 The WECC’s Western Interconnection Synchrophasor Project (WISP)

As a result of American Recovery and Reinvestment Act of 2009 funding, WECC will soon have nearly 700 networked devices installed across the Western Interconnection, sending data in real-time to WECC. WECC will use the data to drive common, interconnection-wide monitoring applications and will make the data available to all WECC reliability entities.

Together, these synchrophasors can identify and analyze system vulnerabilities in real time, and can detect evolving disturbances in the Western interconnection. This “early warning” mechanism enables WECC and partner entities to take timely actions to help avoid potential future widespread system blackouts. The benefits include:

- Improving the ability to avoid large-scale outages
- Increasing transmission usage
- Increasing the use of intermittent renewable generation
- Reducing capacity firming costs for intermittent generation
- Improving Critical Infrastructure Protection and cyber security

- Fostering the exchange of synchrophasor and operating reliability data among the transmission owners, transmission operators, and balancing authorities in the West—an important step in preserving and enhancing reliability

The original nine participants are:

- Bonneville Power Administration
- California ISO /California Energy Commission
- Idaho Power Corporation
- NV Energy
- PacifiCorp
- Pacific Gas & Electric
- Southern California Edison
- Salt River Project
- WECC

Another 10 entities also agreed to participate:

- Alberta Electric System Operator
- Arizona Public Service
- BC Hydro
- Los Angeles Department of Water and Power
- Northwestern Energy
- Public Service of New Mexico
- San Diego Gas and Electric
- Tri-State G&T
- Tucson Electric Power
- Western Area Power Administration

The initial phase was completed March 31, 2013, but activities continue as part of an extension project for the next calendar year in terms of training, control room renovation, continued tool enhancements, and activities among the project's 18 participants.

In addition to detecting electric system disruptions, synchrophasor technology can help companies see and manage intermittent renewable resources—and to deploy ancillary services when necessary. For example, BPA is investing \$39 million for its synchrophasor system, which includes deploying many wind site PMUs.

The achievements include:

- A dedicated, secure Wide Area Network is streaming system data from synchrophasors to WECC's data centers, and between some of the participants.
- WECC's data centers in Vancouver, Washington, and Loveland, Colorado, have been expanded to accommodate the storage of synchrophasor data.

- Synchrophasor applications have been implemented and are in production, including voltage stability, situational awareness, the archival system, modal analysis, and the Wide Area View.
- WECC achieved 100 percent participation by system operators in the WECC Universal Data Sharing Agreement. This agreement provides for the exchange of information among system operators who need synchrophasor and operating reliability data to carry out their reliability responsibilities. The agreement also keeps this data from merchants and marketing functions—thereby assuring the protection of market-sensitive information.

A reliability portal, WECCRC.org, is live, with restricted access to transmission owners, transmission operators, and balancing authorities that have signed WECC’s Universal Data Sharing Agreement. It includes a phasor registry, historical archives, Wide Area View, next day studies, and disturbance reports—all designed to improve the visibility and reliability of the Bulk Electric System.

7.3 Findings from Interviews

Our interviews revealed that the size of an entity affects its readiness to adopt synchrophasor technology, and that time and resources are limiting factors. Larger companies are much more capable of integrating synchrophasor technologies than smaller companies. Smaller entities do not have the institutional depth or financial resources to implement many of these new technologies; they are reluctant to commit to the substantial costs involved unless they are specifically instructed to do so, or they can identify a direct value for their operations. Larger companies also tend to follow research and new technologies much more closely than similarly situated smaller companies. When it comes to adopting technology, size does appear to matter.

The main barriers to more widespread adoption and utilization of synchrophasors right now appear to be time and resources. With the Western Interconnection Synchrophasor Program (WISP), WECC has moved from a previous piecemeal approach that showed some promise to an established infrastructure that has great potential. The data demonstrate their own value; however, there is a very real need to turn the stream of data into visual, actionable information that operators can quickly and easily absorb.

7.4 Summary

There is widespread recognition of the value of synchrophasors for identifying and responding to known grid problems such as interconnection-wide oscillations that have caused large blackouts in the past (e.g., the 1996 West Coast blackouts). However, the tools that utilize synchrophasor technology are in the very early stages of deployment, and operators do not yet have the training or experience necessary to use these tools with confidence. In particular, operating guidelines regarding the actions that should be taken in response to the conditions detected by the tools have not yet been fully codified. Consequently, exemplary practices are still in their infancy. Accordingly, we emphasize the importance of research, development, and demonstration to support the adoption of production-grade, advanced synchrophasor applications operated by experienced personnel who are backed by operating guidelines, ongoing training, and standards guiding their use.

8. Summary and Next Steps

This study interviewed staff involved in day-to-day grid planning and operations across the Western Interconnection. The goal of the interviews was to identify current grid-management policies and practices that may need to be improved to fully implement real-time grid operating recommendations resulting from investigations of the 2003 and 2011 blackouts.

We focused on management policies and practices because what must be done to operate the grid reliably is already well known. NERC's reliability standards are foundational. Compliance is mandatory and therefore a part of everything a firm is doing. This study is not an investigation of (and therefore reaches no conclusions regarding) firms' compliance with reliability standards.

In conjunction with compliance with standards, widespread, shared institutional and management commitment to strong or exemplary operational practices is urgently needed. Based on the interviews we conducted, it appears that these practices are not implemented consistently across the interconnection because of lack of management policies and engagement, including resources, which prioritize and reinforce consistent pursuit of these practices.

State utility regulators, the governing boards of consumer-owned utilities, and the leadership of PMAs play an irreplaceable role in communicating expectations for reliable operation of the grid to the firms they regulate or oversee, and in enforcing these expectations; these bodies have unique influence over firms' priorities with regard to reliability.

This study has provided basic information on real-time grid operations and identified, through interviews, specific areas where improvements to current practices may be warranted. The report also highlighted exemplary practices and promising approaches that were identified through the interview process, which should be considered for broader adoption.

The information is intended to assist state utility regulators, the governing boards of consumer-owned utilities, and the leadership of PMAs in working with the firms they regulate or oversee to review current practices and provide guidance and support for improvement where deemed appropriate (see Appendix A for a list of questions that can be used to discuss current practices and issues).

Table 2 lists the key focus areas in this study, their importance for grid operations, the concerns related to them that we identified in our interviews, and the exemplary practices we recommend for consideration for broader adoption.

Table 2. Summary and Recommendations

Topic	Applicable Entities ^a	Importance for Reliability	Issues Affecting Current Practices	Exemplary Practices for Consideration Broader Adoption
Network Model An electrical representation of all grid elements (transmission facilities), resources (generation facilities), and loads, both internal and external to a company’s transmission system, that can affect the reliability of that transmission system.	TOP BA RC	Provides the basis for routine studies (on multiple time scales, i.e., seasonal, weekly, next-day, day-of) that inform grid planning and operating decisions. An inaccurate or inadequately detailed network model undermines the accuracy and usefulness of the studies that it supports.	Information on conditions relevant to the grid currently under study is sometimes not complete. Missing or inadequate representations include: (1) facilities in neighboring grids; and (2) lower-voltage facilities within the grid under study.	Performance metrics and continuous processes to ensure the adequacy and accuracy of the network model, including: agreements with neighboring utilities for periodic updates and internal procedures for maintaining the network model, which should entail periodic review and validation to ensure the model’s adequacy. Reliance on WECC-led efforts to make updated high-level network models routinely available to grid operators.
Outage Management Processes for coordinating, among grid participants, the planned outages of grid facilities (including protection systems and remedial action schemes).	GOP TOP BA RC	The planned outage (or unavailability) of grid facilities directly affects the options available to grid operators to position (dispatch) the remaining available (non-outaged) grid facilities and to ensure that the grid can withstand and recover from unplanned events.	The approval processes for planned outages are hampered and sometimes compromised when information on planned outage of grid facilities is not shared in a timely manner or is difficult to interpret.	Consistent reliance on agreed upon naming conventions for all grid facilities, used by all who must provide or need to receive this information. Agreed-upon deadlines (greater than one day in advance whenever feasible) for sharing information on planned outages and agreed-upon processes for coordinating actions (for both approving and denying planned outages).

^a BA – balancing authority; TOP – transmission operator; GOP – generation operator; RC – reliability coordinator. See Table B-1. for detailed definitions of each entity designation.

Topic	Applicable Entities ^a	Importance for Reliability	Issues Affecting Current Practices	Exemplary Practices for Consideration Broader Adoption
<p>Next-day Studies</p> <p>Next-day planning studies rely on a correct network model to examine how a range of possible unplanned events (contingencies) might affect reliability during the course of expected future (next-day) grid operating conditions.</p>	<p>TOP BA RC</p>	<p>Next-day studies inform adjustments to the scheduling of grid facilities (including the approval or denial of planned outages) to ensure that the grid can withstand and recover from unplanned events.</p> <p>Sharing of next-day studies enables grid operators to consider how expected conditions on neighboring systems might affect their own operations.</p>	<p>The quality and usefulness of next-day studies are sometimes compromised by (1) insufficient staff resources dedicated to preparation and review of the studies; (2) reliance on an inaccurate network model; and (3) inadequate information on expected grid operating conditions (e.g., lack of information on planned outages).</p> <p>Inadequate sharing of next-day studies and use of compromised next-day studies can result in operators setting inaccurate operational limits (if the studies are wrong, the limits are wrong) or not having enough time to assess risk and take advance steps to resolve potential problems. This increases risk because problems must then be addressed during day-of, real-time operations when there may be fewer options for resolution, and resolution may be more complicated because of the emergence of other, unforeseen conditions.</p>	<p>In addition to the above practices, performance metrics that assess the quality of next-day studies (including performing studies with a wider geographic scope), and management incentives that reward targeted levels of performance.</p> <p>Mutually agreed-upon quality assurance requirements for the preparation of next-day studies (tied to the targeted levels of performance above) and schedules for exchange, review, and joint discussion of next-day studies.</p>
<p>Real-Time Situational Awareness Tools</p> <p>A suite of routinely used software tools (primarily, a state estimator and a real-time contingency analysis/dispatcher’s load flow, using an updated</p>	<p>TOP BA RC</p>	<p>To guide real-time operating decisions and ensure that the grid can withstand and recover from unplanned events, the situational awareness tools that we identify are essential for conducting “what-if” analysis of current grid conditions. This analysis is essential</p>	<p>Operators sometimes do not rely on these tools because of a belief that the results of the tools do not provide useful guidance. The reasons for doubting the tools’ results include: (1) known inaccuracies in the underlying network model (notably,</p>	<p>In addition to the above practices: mutually agreed upon modeling procedures for the remedial action schemes in the Western Interconnection, reliance on real-time contingency analysis performance metrics that assess whether contingencies that occur</p>

Topic	Applicable Entities ^a	Importance for Reliability	Issues Affecting Current Practices	Exemplary Practices for Consideration Broader Adoption
<p>network model/topology) that support systems for communicating information on the current state of the power system (including alarms when thresholds are exceeded) and on how the power system might be affected by unplanned events to operators and that are updated and re-run continuously throughout the operating day with current information on the status of grid facilities.</p>		<p>because, in real time, grid conditions routinely deviate (sometimes, dramatically) from those that were assumed when conducting next-day studies.^b</p>	<p>inadequate modeling of remedial action schemes); (2) incorrect representation of network topology (due in some cases to inadequate information on current outages and the status of non-telemetered switches); and (3) lack of or difficulties in obtaining real-time data on current conditions in neighboring grids.</p>	<p>are correctly identified as well as the accuracy of the analysis of these contingencies, and greater reliance on newly agreed-upon arrangements for the efficient sharing of real-time operating data.^c</p>
<p>Advanced Grid Monitoring Technologies A new class of grid monitoring technologies that augment current SCADA-base monitoring by providing more granular (i.e., very high time-resolution) and time-synchronized information on grid conditions—referred to generically as “synchrophasors.”^d</p>		<p>Synchrophasor technologies enable more granular and wide-area assessment of current grid conditions than is possible with current grid monitoring technologies. The use of the technology for real-time operations is currently limited to monitoring (viewed mainly as a redundant back-up to traditional SCADA monitoring).</p>	<p>The value of synchrophasors is widely recognized for helping operators identify and respond to known grid problems (e.g., interconnection-wide grid oscillations) that have caused large blackouts in the past (e.g., the 1996 west-coast blackouts). However, tools utilizing synchrophasors are in the very early stages of deployment, and operators have not yet had the training or experience necessary to use these tools with confidence. In particular, operating guidelines have not yet</p>	<p>Exemplary practices are still under development. Accordingly, we emphasize the importance of research, development, and demonstration to support adoption of production-grade, advanced applications operated by experienced personnel who are backed by operating guidelines, ongoing training, and standards guiding use of the tools.</p>

^b The importance of these tools depends on the knowledge and experience of the staff operating them and grows with the scale and complexity of the grid that is being operated.

^c The recently agreed-upon WECC Universal Data Sharing agreement is expected to help resolve the issue of data sharing among grid operators although disagreements could remain that could affect the efficacy of information sharing.

^d As a result of ARRA funding, WECC will soon have nearly 700 networked devices installed across the west sending data in real time to WECC. WECC will use the data to drive common, interconnection-wide applications and will make the data available to all WECC reliability entities.

Topic	Applicable Entities ^a	Importance for Reliability	Issues Affecting Current Practices	Exemplary Practices for Consideration Broader Adoption
			<p>been fully codified for directing the actions that should be taken in response to conditions detected by the tools.</p>	

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Appendix A. Sample Questions to Discuss with Utilities

The following questions may be customized or edited for us in discussions with utilities as part of an effort to explore applicability of the exemplary practices found by this study and to set expectations for reliability performance. These are general questions and are not exhaustive. They are more generic than the questions we used for the interviews in this study. An answer of “no” should trigger a follow-up discussion to ensure a shared understanding of the concerns that may be raised for reliability, and the options and trade-offs for addressing these concerns.

Real-Time Model Maintenance

1. Are there data elements to which your entity would like to have immediate access but does not because of requests denied by others?
2. Concerning protection system coordination and modeling of remedial actions schemes, are these elements fully modeled within your real-time analytical systems and do these systems account for remedial action scheme status and operation?
3. What data sharing concerns do you currently have? Which applications do they affect? What are your plans to ensure adequate data sharing among transmission operators or balancing authorities?

Outage Coordination

4. Do you receive, model, and account for all outages above and below 100 kilovolts that affect power flow, voltage support, or larger equipment outages? This would include your owned equipment as well as adjacent entities' equipment to study impacts.
5. Do you have clear cooperation in supporting other organizations and the RC to ensure that outages are fully studied for the operational day on which they are in effect?

Next Day Studies

6. Do you receive accurate and updated operational information from your neighboring transmission operation entities that is adequate for you to do regional studies?
7. Do you validate the accuracy of studies in relation to how operating days actually unfolded?
8. Do you share your studies with adjacent entities?

Situational Awareness

9. Is your energy management system state estimator used and useful?
10. Do you track performance metrics on your state estimator, such as the frequency of converged solutions, accuracy level, gross measurement detection, topology mismatches etc.?
11. Do you have processes to monitor and improve these metrics?
12. Do the lists of contingencies within your RTCA tool encompass your likely system operation limits and all contingent criteria?
13. Does your system accommodate known remedial action schemes or protection system limitations?

New Technologies

14. Does your organization have plans to utilize synchrophasors in real-time grid operations (alarms, state estimation, and additional analytical systems)?
15. What does your organization do to spread the adoption of new technologies that might improve grid reliability?
16. Does your organization sponsor pilot programs of promising technologies and formally evaluate the costs and benefits of those technologies?
17. Does your organization have a department or an individual tasked with analyzing, assessing, and understanding new industry technologies?

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Appendix B. Types of Entities

This appendix summarizes the responsibilities of the different entities involving in jointly ensuring the reliability of the bulk power system. The formal structure is detailed in the NERC Glossary of Terms used in NERC Reliability Standards.¹⁹ The NERC Compliance Registry files contain information concerning the specific functions for which an entity has assumed responsibility.²⁰ Many entities are registered as having more than one function.

Table B-1. Definitions of Entities Focused on in Study

Name	Abbreviation	Role	Examples
Reliability Coordinator	RC	The functional entity that is the highest level of authority responsible for the reliable operation of the bulk electric system; has the wide-area view of the bulk electric system; and has the operating tools, processes, and procedures, including the authority, to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The RC purview is broad enough to enable the calculation of interconnection reliability operating limits (IROL), which may be based on the operating parameters of transmission systems beyond any transmission operator's vision.	The RC function in the west is currently the responsibility of WECC, which has two facilities, one in Vancouver, Washington, and one in Loveland, Colorado.
Balancing Authority	BA	The functional entity that integrates resource plans ahead of time, maintains generation load-interchange-balance within a BA area, and contributes to interconnection frequency in real time.	This is a common function performed by many organizations in the west. WECC maintains a map of these entities that is reproduced below. ²¹
Transmission Operator	TOP	The functional entity that ensures the real-time operating reliability of the transmission assets within a transmission operator area.	A transmission operator coordinates transmission service. The Bonneville Power Administration and the California Independent System Operator (CAISO) are both examples.

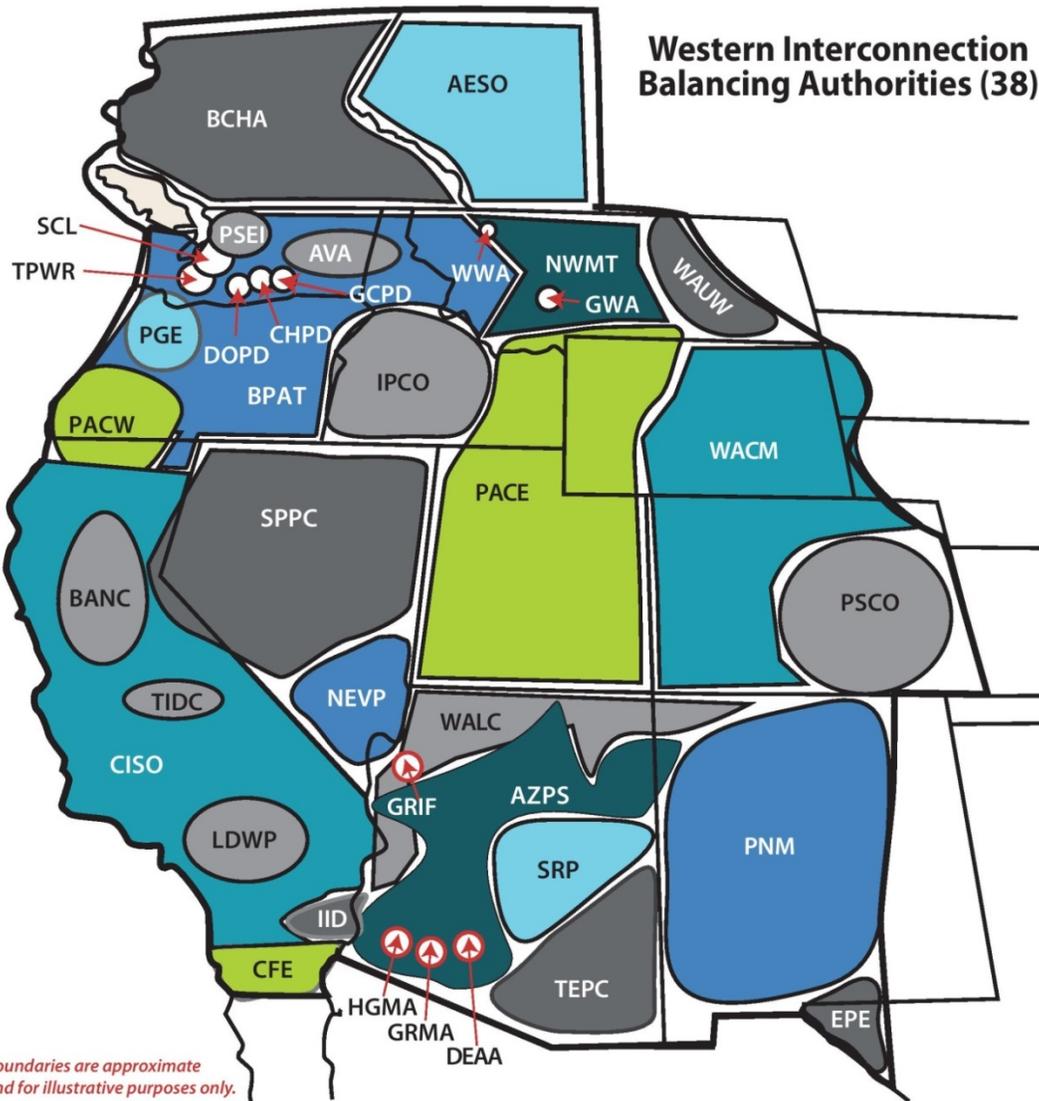
¹⁹ See http://www.nerc.com/files/Glossary_of_Terms.pdf

²⁰ See <http://www.nerc.com/page.php?cid=3|25>.

²¹ See

<http://www.wecc.biz/library/WECC%20Documents/Forms/AllItems.aspx?RootFolder=%2flibrary%2fwecc%20documents%2fpublications&FolderCTID=0x012000278A29140A43884799CB122F821DFD01>

Transmission Owner	TO	The functional entity that owns and maintains transmission facilities.	In some cases the TO and the TOP are the same in that the owner also operates the system. For example, American Power Systems owns and operates its transmission network. Sometimes these functions are separate; for example, Southern California Edison owns and physically maintains the high-voltage transmission network, but CAISO operates the network.
Generation Owner	GO	The functional entity that owns and maintains generating units.	Sometimes the generation owner is different from the generation operator. Companies can be hired to physically run a generation plant just as they can be hired to plan a commercial strategy and schedule accordingly. Some companies have tolling agreements with certain generating units; the toller controls the plant output by appropriately scheduling natural gas and in return receives the electricity. In this case, the physical owner of the plant is commercially passive.
Generation Operator	GOP	The functional entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services.	The generation operator is responsible for scheduling and making the commercial decisions concerning energy production.
Load-Serving Entity	LSE	The functional entity that secures energy and transmission service (and reliability-related services) to serve the electrical demand and energy requirements of its end-use customers.	An LSE serves end-use customers. An example would be Pacific Gas and Electric Company or Sacramento Municipal Utility District.



AESO - Alberta Electric System Operator
 AZPS - Arizona Public Service Company
 AVA - Avista Corporation
 BANC - Balancing Authority of Northern California
 BPAT - Bonneville Power Administration - Transmission
 BCHA - British Columbia Hydro Authority
 CISO - California Independent System Operator
 CFE - Comision Federal de Electricidad
 DEAA - Arlington Valley, LLC
 EPE - El Paso Electric Company
 GRMA - Gila River Power, LP
 GRIF - Griffith Energy, LLC
 IPCO - Idaho Power Company
 IID - Imperial Irrigation District

LDWP - Los Angeles Department of Water and Power
 GWA - NaturEner Power Watch, LLC
 NEVP - Nevada Power Company
 HGMA - New Harquahala Generating Company, LLC
 NWMT - NorthWestern Energy
 PACE - PacifiCorp East
 PACW - PacifiCorp West
 PGE - Portland General Electric Company
 PNM - Public Service Company of New Mexico
 CHPD - PUD No. 1 of Chelan County
 DOPD - PUD No. 1 of Douglas County
 GCPD - PUD No. 2 of Grant County
 PSEI - Puget Sound Energy

SRP - Salt River Project
 SCL - Seattle City Light
 SPPC - Sierra Pacific Power Company
 TPWR - City of Tacoma, Department of Public Utilities
 TEPC - Tucson Electric Power Company
 TIDC - Turlock Irrigation District
 WACM - Western Area Power Administration, Colorado-Missouri Region
 WALC - Western Area Power Administration, Lower Colorado Region
 WAUW - Western Area Power Administration, Upper Great Plains West
 WWA - NaturEner Wind Watch, LLC

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Figure B- 1. Western Interconnection Balancing Authorities

Appendix C. Review of Previous Studies

A number of studies have recommended improvements in the use of real-time tools. Despite these recommendations, it appears that there has not been widespread adoption of these tools. Many of these studies have a similar focus and were motivated by events, such as the Arizona–Southern California outage of September 8, 2011, or in response to other circumstances, such as the need to prepare for incorporation of renewable generation. These studies help show the current state of real-time tools technology and are useful as a backdrop for studying new tools. Transmission operators need to ensure that current, proven technology is in place and then augment that technology with the emerging new technologies such as synchrophasors.

Arizona–Southern California Outages of September 8, 2011

This outage, which blacked out 2.7M customers for up to 12 hours on the date in question, is well known in the industry. It was the subject of numerous studies by the affected entities, including a study by FERC and NERC (FERC/NERC Staff Report²²). The FERC/NERC study produced a number of findings and recommendations. Some of these are relevant to the issue at hand, in particular findings 11-16 concerning situational awareness as well as a few others:

FERC_NERC Recommendation 2: TOPs and BAs should ensure that their next-day studies reflect next-day operating conditions external to their system. They should take the necessary steps to ensure the free exchange of data and studies.

FERC_NERC Recommendation 3: TOPs and RCs should ensure that next-day studies include facilities below 100 [kilovolts] kV that can affect the Bulk Electric System (BES) reliability.

FERC_NERC Recommendation 11: Lack of real-time external visibility; TOPs need sufficient data to monitor external facilities that have a direct bearing on the reliability of their system. The State Estimator and RTCA should represent the critical systems needed for the reliability of the bulk power system.

FERC_NERC Recommendation 12: TOPs need to ensure that the real-time tools used provide operators with sufficient situational awareness to reliably operate the system.

FERC_NERC Recommendation 13: TOPs should ensure that post-contingency plans, including the effect of relays that automatically isolate equipment, allow operators sufficient time to mitigate overloads.

FERC_NERC Recommendation 27: TOPS should have tools to determine phase angle after the loss of transmission lines, and further should have operating plans to reclose lines with large phase angle differences.

These recommendations are all in various stages of implementation across WECC, and they speak to the real-time tools that are perceived to be necessary to reliably operate the grid. Some of the recommendations, such as recommendation 12 “TOPs need to ensure that the real-time tools used provide operators with sufficient situational awareness to reliably operate the system,”

²² <http://www.wecc.biz/About/sept8/Documents/FERC%20NERC%20Joint%20Report%20Arizona-Southern%20California%20Outages%20on%20September%208,%202011.pdf>

are less specific; however, any preventable grid event that occurs indicates a lack of sufficient situational awareness.

NERC Real-Time Tools Survey Analysis and Recommendations²³

In the aftermath of the August 14, 2003 blackout that affected more than 50 million people, a number of reports were issued that sought to ensure that this sort of event was prevented in the future. One of these reports was the findings and recommendations of the North American Electric Reliability Corporation (NERC) Real-Time Tools Best Practices Task Force (RTBPTF). Although this report is now more than four years old, it remains useful because it sought to determine what real-time tools were necessary to ensure reliable grid operation. It also made specific recommendations, which is not the case in all reports. That is, many reports recommend tools in a general manner, meaning that they specify that operators need sufficient tools to give them adequate situational awareness to run the grid reliably. The reason for this is simple: a blackout is enormously expensive economically. The value of lost load (VoLL) is often proxied at \$10,000/megawatt-hour although the value is lower if the blackout persists. Whatever the size of the VoLL, it dwarfs the incremental expense of procuring and implementing real-time tools.

The general expectation is simply that electric system reliability is maintained all the time, and no blackouts are allowed because they are all preventable except under the most extreme conditions; moreover, it is expected that even in extreme situations blackouts should be local and easy to recover from. Working back from this imperative, we find the standard general recommendation from the entities studying major blackouts, which is that real-time operators must have the tools that they require to reliably operate the grid. The tools that they require are assumed to be whatever tools exist that will give operators sufficient situational awareness²⁴ to operate the grid reliably. Eventually these recommendations must be fleshed out to specifically identify these tools. The RTBPTF provided a useful service by specifically recommending certain tools. Having any or all of these tools will not guarantee reliable operation of the grid. In fact, there are so many unknowns that reliable operation is impossible to guarantee. However, using these tools increases the situational awareness of the grid operators, and the better prepared the grid operators are, the less likely that any grid event will turn into a cascading outage.

Real-Time Tools Best Practices Task Force Recommendations

The task force recommended a reliability toolbox which had five elements:

- Toolbox_1. **Telemetry data systems** – These systems are common and provide the data needed by more complex systems. The task force did not so much recommend their presence, because these systems they are already standard products, but recommended *standards* for telemetry systems, essentially pushing for more frequent and better-quality data upon which other applications could build.

²³ See <http://www.nerc.com/filez/rtbptf.html>

²⁴ The task force defined situational awareness as: “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.”

Telemetry data are not very useful in raw form because the volume of these data is so large that it cannot be absorbed in any meaningful time frame.

- Toolbox_2. **Network topology processor** – A network topology processor, like telemetry data, is essentially a support tool. It has two main functions: it supports visualization tools in showing isolated equipment, and it converts node/breaker data elements into a bus/branch model commonly used by RTCA and the state estimator.
- Toolbox_3. **Alarm tools** – These auditory or visual alerts are critical. Ideally, alarm tools are calibrated across different applications so that, no matter what the application, the type of alarm indicates the likely severity of the condition. Audible alarms are rated higher than visual alarms, and the number of alarms must be carefully calibrated so as not to overwhelm the operator during an event.
- Toolbox_4. **State estimator** – The state estimator uses statistical analysis and raw telemetered data to estimate the state of the grid. State estimators are vital to contingency analysis and power flow applications as well as to many market applications. In centralized market systems, the state estimator often feeds the real-time market application so that the market system can increment or decrement intelligently based on the state of the grid and the load forecast. Further, the state estimator feeds real-time contingency analysis, which is arguably the most critical real-time tool from a reliability perspective. The task force recommended not just the presence of a state estimator but also performance metrics to verify that the state estimator is functional and working.
- Toolbox_5. **Contingency analysis** – Contingency analysis simulates a power flow and calculates voltages and loading in the aftermath of a particular contingency. That is, contingency analysis attempts to predict the state of the grid following a predicted grid event. This analysis relies on a converged solution from the state estimator. If done properly, contingency analysis is enormously valuable because it allows the operator to take mitigating actions prior to a contingency event so that recovery from the event takes place within prescribed time frames. As in their state estimator recommendation, the task force recommended both the presence of contingency analysis and performance standards to ensure that the analysis is functioning effectively.

In addition to recommending the above real-time tools, the RTBPTF made a series of recommendations concerning situational awareness (termed Enhanced Operator Situational Awareness [EOSA]):

- EOSA_1. **Power-flow simulations** – The task force recommended that one-hour-ahead power flow simulations be compulsory after any major event, whether a forced outage, an extreme load event, or any other unusual circumstance. The task force thought that making this a requirement would improve operator awareness.
- EOSA_2. **Conservative operations plans** – The task force felt that a crucial element of reliable operation was for the TOP to have a conservative operation plan. This is

simply a disposition of the system in a known safe and reliable manner whereby flows are well within known tolerances. When an unexpected grid event occurs, shifting from an everyday disposition to a known safe disposition would allow grid operators to operate under safe conditions while trying to analyze the recent unexpected event. This known safety point is similar in nature to the disposition of the grid prior to major weather events such as hurricanes.

- EOSA_3. **Load-shed capability awareness** – An essential element of situational awareness is knowledge of the resources one has available to use in responding to a grid event. These resources include real and reactive reserves as well as the critical ability to shed load quickly, either via demand-side management programs or via controlled load-shedding as a sacrifice to preserve the integrity of the remaining system. The task force identified as an issue the fact that operators are not constantly aware of their load-shed capability.
- EOSA_4. **Critical applications and facilities monitoring** – This task force recommendation states that not only should critical facilities be monitored, but also the toolbox applications mentioned earlier, to ensure that they are used and useful. In addition, there should be document retention standards and logs associated with these tasks.
- EOSA_5. **Visualization techniques** – Visualization methods are a crucial element of situational awareness because visual representation speeds operators' comprehension of data that would be overwhelmingly time-consuming to comprehend in raw form. Unfortunately, it is difficult to objectively measure or set standards for effective visual representation of data.