STEPS TO ESTABLISH A REAL-TIME TRANSMISSION MONITORING SYSTEM FOR TRANSMISSION OWNERS AND OPERATORS WITHIN THE EASTERN AND WESTERN INTERCONNECTIONS

A REPORT TO CONGRESS PURSUANT TO SECTION 1839 OF THE ENERGY POLICY ACT OF 2005

Prepared by

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Report to Congress

Joint Report by the Department of Energy and Federal Energy Regulatory Commission on Steps to Establish a Real-Time Transmission Monitoring System for Transmission Owners and Operators within the Eastern and Western Interconnections

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Executive Summary

In August 2003, an electrical outage in one state precipitated a cascading blackout across seven other states and as far north as a province in Canada, leaving more than 50 million people without power.[1] The 2003 event was the largest blackout in the history of the United States, the eighth large-scale blackout experienced by North America since 1965,[2] and the fourth U.S. blackout caused in part by deficiencies in the system that monitors the electric grid and by a lack of awareness of deteriorating conditions by the operators who monitor the system.[3]

Section 1839 of the Energy Policy Act of 2005 (EPAct 2005)[4] directs the Secretary of Energy (DOE) and the Federal Energy Regulatory Commission (Commission) to study and report to Congress on the steps that must be taken to establish a system to make available to all transmission owners and Regional Transmission Organizations (RTOs)[5]

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[1] U.S. Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, at 1 (Final Blackout Report). The Task Force investigated the causes of the 2003 blackout and recommended actions be taken to prevent future widespread outages.

[2] *Id*. at 104-07. The other seven blackouts include the 1965 Northeast blackout, the 1977 New York City blackout, the 1982 and the July and August of 1996 West Coast blackouts, the 1998 Upper Midwest blackout, and the 1999 Northeast U.S. outages and non-outage disturbances.

[3] *Id.* at 104-06. The other instances in which monitoring system failures or lack of situational awareness contributed to blackouts include the November 1965 Northeast blackout, the July 1977 New York City blackout, and the July 1996 West Coast blackout.

[4] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1839, 119 Stat. 594, 1142 (2005) (hereinafter "EPAct 2005").

[5] EPAct 2005 defines an RTO as an entity of sufficient regional scope approved by the Commission: (a) to exercise operational or functional control of facilities used for the transmission of electric energy in interstate commerce; and (b) to ensure nondiscriminatory access to the facilities. *See*

within the Eastern and Western Interconnections real-time information on the functional status of all transmission lines within such Interconnections.[6] The study is to assess technical means for implementing a transmission information system and identify the steps the Commission or Congress would need to take to require implementation of such system.[7] This Joint Report responds to Congress' directive and addresses whether technology provides a means to address deficiencies in the transmission monitoring system and to provide better information to all system operators. The report focuses not on whether such a system should be deployed but offers a technical evaluation of how such a system could be established if one is to be pursued. This joint report merely describes the steps necessary to establish and implement an interconnection-wide monitoring system and does not require the Commission to implement such a system. Finally, this report acknowledges that a feasibility determination is necessary prior to any action to implement a real-time monitoring system and that the implementation of such a system is beyond the scope of Congress' direction in section 1839 of EPAct 2005.

This report finds that:

- technology currently exists that could be used to establish a real-time transmission monitoring system to improve the reliability of the nation's bulk power system; and
- emerging technologies hold the promise of greatly enhancing transmission system integrity and operator situational awareness, thereby reducing the possibility of regional and inter-regional blackouts.

The analysis herein identifies nine steps that could be taken to establish, and two steps that could be taken to implement, an interconnection-wide real-time monitoring system that could give a near-instant picture of the transmission system's health. Specifically, the report identifies a real-time transmission monitoring system that could provide the following primary and secondary benefits to enhance the situational awareness of system

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EPAct 2005 § 1291, 119 Stat. 594, 984 (to be codified as amended at 16 U.S.C. § 796 in the Federal Power Act (FPA)). Commission-approved RTOs are those that have filed for and received approval from the Commission for RTO status pursuant to Order No. 2000. *Regional Transmission Organizations*, Order No. 2000, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,092 (2000), *petitions for review dismissed sub nom. Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[6] There are three distinct power grids or "interconnections" in North America. The Eastern Interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces. The Western Interconnection includes the western third of the continental United States (excluding Alaska), the Canadian provinces of Alberta and British Columbia, and a portion of Baja-California-Norte-Mexico. The third interconnection comprises most of the state of Texas. Appendix C provides a map detailing the geographical boundaries of these interconnections.

[7] EPAct 2005 § 1839, 119 Stat. 594, 1142.

operators, should such a system be implemented.

The primary benefits of a real-time transmission monitoring system could be to:

- provide early warning of deteriorating system conditions, so operators can take corrective actions;
- limit the cascading effect of disturbances (by providing wide-area system visibility); and
- improve transmission reliability planning and allow for immediate post-disturbance analysis and visualization through the use of archived monitoring system data.

The secondary benefits of a real-time transmission monitoring system could be to:

- provide more diagnostic tools than are currently available;
- allow for the more effective use of automatic controls for self-correction such as automatic switching or controlling the flow of power; and
- improve computer models of the power system.

This report concludes that if an interconnection-wide transmission monitoring system is pursued:

- implementation of the system could occur in two phases, with the first phase focusing on upgrading the current Supervisory Control and Data Acquisition[8] (SCADA)-based real-time monitoring system (Phase I) and the second phase focusing on developing a better real-time monitoring system based on emerging technologies (Phase II);
- other technical features of a real-time transmission monitoring system require that uniform data and common data storage be used across the system so that all system operators can share and use each other's data with ease; and
- the system will need to have common visualization features so that all users will view the real-time information in a similar fashion.

The design process for Phase I could be started without delay since it would be based on the existing SCADA system and require data collection from a limited number of SCADA data sources, collected every few seconds. Phase II would be based on advanced technology and require data collection from thousands of data sources collected many times per second. If an interconnection-wide transmission monitoring system is to be installed, it is recommended that planning for Phase II begin at the same time Phase I is being designed.

This Joint Report recommends that if an interconnection-wide transmission monitoring system is pursued:

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[8] A system of remote control and telemetry used to monitor and control the electric system.

- the Commission, in consultation with DOE, engage the soon-to-be established Electric Reliability Organization (ERO) that is certified by the Commission pursuant to section 215 of the FPA, to investigate and report on the feasibility, cost, and timeline to establish such a system; and
- the ERO develop its report using technical conferences, industry meetings, and independent studies.

The analysis from the ERO report is expected to provide critical information that could be used to develop mandatory reliability standards necessary for the implementation of a real-time monitoring system. Implementation of an interconnection-wide real-time monitoring system, as assessed in this analysis, could enhance the situational awareness of transmission system operators, as recommended in the Final Blackout Report, thereby addressing one of the "principal causes"[9] of the blackout.

[9] Final Blackout Report, *supra* note 1, at 159, Recommendation Number 22.

Section I: Introduction

The United States' electric transmission system is so intricately connected and interdependent that an electrical outage in just one state can cause cascading blackouts throughout many states, even through a neighboring country. Just such an event occurred on August 14, 2003, when an electrical outage that began in Ohio caused a widespread blackout affecting 50 million people in Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey, and the Canadian province of Ontario.[10]

On August 15, 2003, President George W. Bush and then-Prime Minister Jean Chrétien directed that a joint U.S.-Canada Power System Outage Task Force be established to investigate the causes of this blackout. The Final Blackout Report identified, among other things, failures in the system that monitors the electric grid and the operators' lack of situational awareness, which "was in turn the result of inadequate reliability tools and backup capabilities."[11] Some of the monitoring failures identified in the Final Blackout Report were:

- the failure of operators to detect the loss of transmission lines, to recognize or understand the deteriorating condition of the system, and to recognize the need for action due to insufficient information;[12]
- the failure of operators to assess and understand the inadequacies of the system, particularly in regard to voltage stability;[13] and
- the failure of the interconnected grid's reliability organizations to provide effective real-time diagnostic support.[14]

The above inadequacies (which highlight the lack of situational awareness), coupled with the interdependencies and the interconnected nature of the nation's electric grid, demonstrate the need to establish an interconnection-wide monitoring system that could be

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[10] *Id*. at 1. According to the report, this outage cost the United States between $4 billion and $10 billion and some parts of the United States were without power for up to four days.

[11] *Id*. at 159, Recommendation Number 22. In addition to the deficiencies in tools for better visualization, the Final Blackout Report identified ineffective vegetation management practices (which allowed trees to interfere with energized lines) and inadequate operator training (personnel failed to declare an emergency and take timely and appropriate action) as contributing factors to the blackout. *See id.* at 59, 157.

[12] *Id*.

[13] *Id.* Voltage stability is defined as the condition of an electric system in which the sustained voltage level is controllable and within predetermined limits.

[14] *Id.*

used by owners and operators to provide an early warning so that preemptive actions can be taken to limit or prevent cascading outages.

The Final Blackout Report also provided the following recommendations for avoiding future blackouts:

- the Commission and appropriate authorities in Canada should establish requirements for collecting and reporting of data needed for post-blackout analyses;[15]
- DOE should expand its research programs on reliability-related tools and technologies;[16]
- the North American Electric Reliability Council (NERC)[17] should evaluate and adopt better real-time tools for operators and Reliability Coordinators (RC);[18]
- NERC should improve the quality of system modeling data and data exchange practices;[19]
- NERC, the Commission, and appropriate Canadian authorities should require the use of time-synchronized data recorders;[20] and
- corporations should establish clear authority and ownership for physical and cyber security.[21]

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[15] *Id.* at 148, Recommendation Number 11.

[16] *Id.* at 149, Recommendation Number 13.

[17] NERC is a not-for-profit organization formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America through, among other things, the development of reliability standards. Appendix G provides a map illustrating the 10 regional reliability councils that comprise NERC to date.

[18] *Id.* at 159, Recommendation Number 22. An RC is an individual or organization responsible for the safe and reliable operation of the interconnected transmission system for its defined area, which is comprised of a combination of several balancing entities who are responsible for "balancing" generation and load in real time. The RC facilitates the sharing of data and information about the status of the Balancing Authorities for which it is responsible, establishes a security policy for these Balancing Authorities and its interconnections, and coordinates emergency operating procedures that rely on common operating technology, criteria, and standards.

[19] *Id.* at 160, Recommendation Number 24. System modeling data are used in power system computer models for simulating steady state and transient state of the power system.

[20] *Id.* at 162, Recommendation Number 28. Time-synchronized data recorders sample data synchronously at selected locations throughout the power system through the use of GPS (Global Positioning System). The internal GPS satellite receiver-clock coordinates the sampling process to ensure that data is sampled at the same instant in time by the devices installed at remote locations throughout the power system.

[21] *Id.* at 169, Recommendation Number 43.

These monitoring system failures that occurred during the 2003 blackout and the recommendations in the Final Blackout Report informed DOE and the Commission in preparing this report, which responds to the Congressional directives in section 1839 of EPAct 2005:

> Within six months after the date of enactment of this Act, the Secretary [of Energy] and the Federal Energy Regulatory Commission shall study and report to Congress on the steps which must be taken to establish a system to make available to all transmission system owners and Regional Transmission Organizations (as defined in the [FPA]) within the Eastern and Western Interconnections real-time information on the functional status of all transmission lines within such Interconnections. In such study, the Commission shall assess technical means for implementing such transmission information system and identify the steps the Commission or Congress must take to require implementation of such system.[22]

Specifically, section II of this report identifies, through a technical analysis, nine steps that could be taken to establish an interconnection-wide real-time transmission monitoring system. It begins with defining the terms "real-time information" and "functional status of all transmission lines in the interconnection." Next, it evaluates existing real-time monitoring technologies, namely the SCADA systems and the Energy Management System (EMS),[23] which supervise, control, optimize, and manage electric generation and transmission. Finally, this section identifies an advanced real-time monitoring and visualization system now under development and prototype deployment.

Section III articulates, per the direction in section 1839 of EPAct 2005, and with the assumption that an interconnection-wide real-time transmission monitoring system is feasible and will be pursued, the steps the Commission would have to take to implement such a system. These steps address institutional, planning, and financial issues. Section IV offers conclusions and recommendations. The report also contains a number of appendices, offering a list of acronyms, a glossary of terms, a functional status matrix, a map detailing the geographical boundaries of the interconnections, a map of NERC regional reliability councils, and other relevant technical information.

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[22] EPAct 2005 § 1839, 119 Stat. 594, 1142 (2005).

[23] EMS is a computer control system used by electric utility dispatchers to monitor the real-time performance of various elements of an electric system and to control generation and transmission facilities.

Section II: Assessment of Technical Means and Steps to Establish a Transmission Monitoring System

Study Assumptions and Approach

Section 1839 of EPAct 2005 directed DOE and the Commission to study and report to Congress on the steps that must be taken to establish a system to make available real-time information on the functional status of all transmission lines within the Eastern and Western Interconnections. The steps identified in the report are based on technical evaluations of the relevant literature and the technical expertise of the Commission and DOE staff electrical engineers with extensive experience in power system operations. The study's analysis considers systems with voltage levels of 69,000 volts (69 kilovolts or 69kV) and higher, which generally match current transmission system models.[24] This section of the report focuses on how, rather than whether, an interconnection-wide real-time monitoring system should be deployed.

The following nine steps should be taken if an interconnection-wide real-time monitoring system is to be pursued:

Step 1. Define what a real-time monitoring system is, what it should accomplish, and how to accomplish this goal, including an explanation of the terms "real-time information" and "functional status."

Step 2. Evaluate existing real-time monitoring technologies and their limitations.

Step 3. Identify the communications infrastructure required and related security and operating issues.

Step 4. Define data requirements.

Step 5. Identify promising emerging technologies.

Step 6. Decide what data should be shared, with whom, and when.

Step 7. Decide who should operate, use, and maintain the system.

[24] The transmission system is divided into the following categories based on voltage levels as defined by the American National Standards Institute (ANSI) and the Institute of Electrical and Electronics Engineers (IEEE) standards: Extra High Voltage (EHV) of 240 kV and higher (ANSI/IEEE Std. 49); High Voltage (HV) which includes 100 kV to 230 kV (ANSI/IEEE Std. 260); and Medium Voltage, which is less than 1 kV to 72.5 kV (ANSI/IEEE Std. 49).

Step 8. Identify potential participants involved in establishing a real-time monitoring system.

Step 9. Consider cost and funding issues.

Step 1. Define What a Real-Time Monitoring System is, What it Should Accomplish, and How to Accomplish it

A real-time monitoring system collects "real-time information" of the transmission system that consists of measurements of selected system elements that are collected by SCADA and/or Intelligent Electronic Devices (IEDs)[25] at various time intervals. These measurements are taken at generators, substations,[26] and at selected other points on the system, and could be used, stored in local computer databases, or sent by telecommunication lines to remote computer databases.

A real-time monitoring system should provide operators with real-time information about the transmission system's "functional status," (i.e., real-time information about the operational status of the transmission system and its components). This information includes direct measurements such as switching status of the transmission line (i.e., in service/out of service), amount of sag on the line, power flow in the line, and interconnection frequency. Other information is calculated from measurements such as whether equipment is being overloaded.

Operators could run the transmission system more reliably than is possible today if they know the functional status of all transmission lines. For example, by monitoring current flow, an operator could perceive system problems such as transmission line overloading. Thus, a real-time monitoring system would capture the real-time measurement of the functional status of the transmission system and should provide critical information such as low voltage condition[27] or low reactive power reserve margin[28] in a manner that can be quickly and easily ascertained by an operator, such as colors and alarms. Appendix D presents a comprehensive list of what constitutes "functional status."

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[25] An IED monitors grid operational parameters and is capable of independent protective action at a substation. A more detailed definition can be found in Appendix B, Glossary.

[26] A substation is a facility, generally including a small building, with a fenced-in gravel yard containing switches, transformers, and other equipment used to adjust voltages and monitor circuits.

[27] A low voltage condition occurs when the voltage level falls below a nominal value. A sustained low voltage condition could lead to voltage collapse and a possible blackout.

[28] Reactive power reserve margin refers to the amount of reactive power available to the system. Reactive power is used locally to boost the system voltage.

Step 2. *Evaluate Existing Real-Time Monitoring Technologies and their Limitations*

The next step in evaluating how a real-time monitoring system could be established is to identify the different types of available monitoring technologies that could provide a near-term monitoring system. While there are some advanced technologies that show promise for establishing a more advanced real-time information system for use throughout the interconnections, most of these technologies are in the development phase or in an early stage of implementation. Therefore, an initial approach would be to utilize the existing technology until advanced technologies could be developed and integrated into a more sophisticated system.

By far the most commonly used monitoring system throughout the energy utility industry is the SCADA and EMS structure that monitors, controls, optimizes, and manages generation and transmission systems. SCADA and EMS are used by transmission entities, including Independent System Operators (ISOs),[29] RTOs, transmission owners, and operators. These systems perform a number of functions, including:

- collecting, storing, and analyzing data from hundreds of thousands of data points in national or regional computer networks;
- modeling networks;
- simulating power operation;
- analyzing faults;
- studying outages; and
- interfacing with energy trading markets.

SCADA systems are also used in industrial applications to control distributed systems from a master location, such as a control center.[30] SCADA acts in two ways; it provides data such as meter readings and equipment status to operators, and it allows operators to control the equipment in the field. A SCADA system collects real-time transmission system measurements every two to four seconds.

Today, data from SCADA and EMS systems are available throughout the Western and Eastern Interconnections from ISOs, RTOs, and Balancing Authorities (BAs).[31] SCADA

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[29] EPAct 2005 § 1291(b)(1), 119 Stat. 594, 984. An ISO is an entity approved by the Commission to (a) exercise operational or functional control of facilities used for the transmission of electric energy in interstate commerce, and (b) ensure nondiscriminatory access to the facilities.

[30] For instance, SCADA systems are used in the water, oil, and natural gas infrastructures to monitor product flows, allow controllers to turn on or off valves, and to keep track of product sales.

[31] A Balancing Authority is the entity responsible for making certain that the area's power requirements are scheduled and developed by dynamically balancing load and generation in its area. For example, the New York Independent System Operator is the Balancing Authority for the state of New

and EMS therefore are a viable platform if one were interested in establishing a real-time monitoring system that would be easily accessible in the near term to all users.[32] The majority -- but not all[33] -- of the SCADA data is transmitted from the regional BAs to the ISOs and RTOs and will be available to the real-time monitoring system. Some of the data that are not transmitted to the ISOs and RTOs could be collected from the appropriate BA's SCADA system and then transmitted throughout the interconnections.

SCADA systems, however, have a number of limitations that hinder their use for carrying out the functions of a more technologically sophisticated real-time monitoring system for the Eastern and Western Interconnections. SCADA systems generally are based on closed and proprietary software and hardware architectures. The data is stored in proprietary databases with specific structures that are unique to the architecture.[34] As a result, it is cumbersome to exchange data openly and freely. Currently, the amount and format of data exchanged between SCADA and EMS systems is covered through bilateral agreements between the parties. While this process may work for several entities, a standardized data format is required if a common visualization system is to be developed. Therefore, if a real-time monitoring system for both the Eastern and Western Interconnections is to be pursued, adoption of a common format for use in data exchange among all entities would be critical. One possible solution could be to adopt Common Information Model (CIM) Standards. CIM provides a common definition of management information for systems, networks, applications, and services, and allows for vendor extensions. CIM's common definitions enable vendors to exchange semantically rich management information between systems throughout the network.

Step 3. Identify Required Communications and Related Security and Operating Issues

The sharing of such vast amounts of data among a large number of users requires the establishment of a communications infrastructure. If an interconnection-wide real-time monitoring system is to be established, the next step would be to identify the communications equipment needed to facilitate data sharing. In addition, other related

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York. A Balancing Authority area is an electric system bounded by interconnection metering and telemetry, which measures the current, voltage, power flow, and status of transmission equipment.

[32] The current SCADA and EMS systems can provide a SCADA-based real-time monitoring system until such time that emerging technologies move from the development to the deployment stage. These emerging technologies are discussed later in this report.

[33] Not all the real-time measurements are transmitted to SCADA/EMS due to the communications and performance limitations inherent in these systems.

[34] Proprietary architecture is a closed form of architecture that is privately owned and controlled by a company. It implies that the company has not disclosed specifications that would allow other companies to duplicate the architecture.

factors should also be considered, such as security (confidentiality, cyber, and physical), ownership, and maintenance of the communications system.

Data collection process used throughout the transmission system relies on a variety of metering devices. In SCADA systems, metering devices communicate with a control center using Remote Telemetry Units (RTUs). An RTU electronically collects data from metering devices, formats the data, and sends it to a central data collector. Communications between RTUs and the SCADA and EMS have traditionally used combinations of radio, microwave, and modem connections. While this is a convenient way to communicate data, it poses security risks, including the compromise of data confidentiality that may be accessed and viewed by unauthorized entities. This issue has been investigated and addressed in a project sponsored by DOE's Office of Energy Assurance that utilized encryption and authenticated communications from the substation to the SCADA control center.[35]

Communication between the SCADA systems of different EMS control centers and among utilities and all other electricity users is typically provided by Inter-Control Center Communications Protocol (ICCP).[36] ICCP operates across a wide range of connections, using dedicated routing devices for the exchange of real-time and historical power system data. A graphic representation of a SCADA and EMS communications system is shown in Appendix E.

Today's communication infrastructure, however, has a number of limitations that hinder the transfer of data from substation RTUs to other monitoring systems. For instance, due to the low-bandwidth[37] of existing communications protocols, SCADA communications protocols are designed to be very compact and most are designed to send information to the master SCADA station only when the master station polls the RTU. If, for example, the master station polls the RTU every four seconds, the data in the SCADA system is not truly real-time – it is as much as four seconds old. During transient events (e.g., power oscillations due to an equipment trip caused by a protection relay as a response to an overload condition), measured data could change as quickly as 60 times per second. Compact SCADA protocols limit the amount of information that can be transmitted, and

[35] U.S. Department of Energy, *Cyber Security for Utility Operations*, *available at* http://www.sandia.gov/scada/documents/FinalReport_M63SNL34_18Apr05.pdf.

[36] ICCP is an international standard for real-time data communication among control centers, utilities, power pools, regional control centers, and non-utility generators. ICCP defines a set of objectives and services for data exchanges. ICCP was developed largely by the Electric Power Research Institute (EPRI) in the 1990s in collaboration with energy companies, energy company consultants, protocol providers, and energy management system vendors.

[37] Bandwidth is a measure of the capacity of a communication's channel. The higher a channel's bandwidth, the more information it can carry.

require use of abbreviations, which could make data difficult to interpret.

Another limitation of current systems is that the grid's communications between different EMS control centers could be inadequate, causing operators to be unaware of disturbances in neighboring BAs. As occurred in the August 14, 2003 blackout, operators in neighboring BAs missed opportunities to limit the spread of trouble because they relied on manually initiated telephone conversations for information about transmission lines outside their own area rather than on a real-time visualization system.[38]

As more computer processing power is embedded within new SCADA equipment, there is a demand for more information to be transferred, requiring higher data-transfer rates. The challenge lies in having SCADA equipment and protocols work together with modern networks and increased computer power.

As for communications requirements of owners and operators, most control center operators and transmission operators only need information about transmission lines in their area and neighboring areas. Data from local meters are collected at a local data center, and any calculations needed for the operators are done on the local data. However, a distributed communication network allows for a more efficient way to share data. To achieve such efficiency, local data centers could be interconnected to share information among areas as specified by Recommendation Number 24 of the Final Blackout Report.[39]

Security issues must also be addressed when developing an interconnection-wide real-time transmission monitoring system. Many levels of security need to be achieved in a communications infrastructure. For communication protocols and the equipment that read these protocols, the available security technologies include encryption, authorization, authentication, intrusion detection, and filtering of communications and network traffic.[40] These security technologies require more bandwidth, memory, and processing power than most SCADA components have.

Although ICCP was developed with built-in security measures, today's interconnected environment and large-scale exchange of confidential information appear to require additional security measures to ensure uninterrupted transmission and generation system operations.

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[38] Final Blackout Report, *supra* note 1, at 161.

[39] *Id.* at 160, Recommendation Number 24.

[40] General Accouting Office (GAO) Report, *Critical Infrastructure Protection Challenges in Securing Control Systems*, GAO 04 140T, October 1, 2003 at 12, *available at* http://www.gao.gov/new.items/d04140t.pdf.

Cyber security is most effective in conjunction with physical security measures, such as secure physical access to all computers, and locks, fences, guards, and surveillance cameras around communications facilities. One step toward ensuring physical security would be to evaluate all connections to the SCADA system, disconnecting those that are unnecessary and strengthening the security of those that are necessary. Remote sites connected to the SCADA system are especially vulnerable because they are often unmanned. SCADA network owners could take steps to ensure that any communication links from those sites are secure (e.g., communications cables cannot be tapped, radio or microwave links are not exploitable, and there is no unauthorized access through computer terminals or wireless networks).[41]

The bulk electric power grid, with its geographically dispersed assets and data flows, may lend itself to a "publish-and-subscribe" communication architecture. In this type of networked system, some intelligent devices "publish" information that is of value to other "subscribers." A publisher might be a residential watt-hour meter, and a subscriber might be a utility's billing software system. In this case the billing software would subscribe to the output of the homeowner's meter for monthly readings.

One such application currently being developed for electric power "publish-and-subscribe" systems is called "middleware."[42] Middleware is a communications layer that allows applications to interact across hardware and network environments, using uniform protocols to ease communications compared to what is possible in current systems. It is unclear whether industry will adopt an architecture that involves middleware, but an interconnection-wide transmission monitoring network may be a good application for this technology.

The communications equipment between local utilities and a central monitoring system could be owned by a central entity such as the ERO, especially if the monitoring system relies on a centralized communication architecture. Alternatively, there could be one set of central communication equipment for each region, owned by the regional entity or the TOs in the region. This approach would work if the monitoring system uses a distributed communications architecture, as described above.

Much of the metering and communications equipment needed to implement an interconnection-wide transmission monitoring system is already in place and owned by local utilities or transmission operators. Each local utility could purchase and maintain its own equipment for communicating between its system and an interconnection-wide

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[41] U.S. Department of Energy, *21 Steps to Improve Cyber Security of SCADA Networks*, September 9, 2002, at 3-5.

[42] C. Hauser, D. Bakken A. Bose, *A Failure to Communicate*, IEEE POWER & ENERGY MAG., March/April 2005, at 47.

monitoring system. NERC Monitoring System Conditions Standard (TOP-006-0) requires RCs, TOs, and BAs to monitor specific equipment status and system conditions in real time.[43]

Step 4. Define Data Requirements

Once the existing real-time monitoring technologies and their limitations are evaluated, it would be necessary to identify the required data for use in a real-time transmission monitoring system. At the minimum, it would be necessary to know the following: (1) the data available; (2) what data are being archived to support post-disturbance analysis; and (3) and the level of standard formats being used for storing real-time data.

Currently, there is a limitation on the amount and type of available data as it often depends on what the transmission operator considers necessary to collect. Some of these measurements include generator output quantities (i.e., power, voltage, status) and tie-line flow information (i.e., power flow, frequency). This information would have to be collected at least every four seconds to meet the performance standards of automatic generation control (AGC).[44] Although transmission operators are not required by FERC regulations to retain real-time data, a number of Commission regulations exist that govern the retention of operational data.[45] Data being collected at a substation will likely be different from data being collected at a control center. Further, there are differences in the applications of, and calculations being done with, the data. The goal is to determine the common level of data needed for reliable operation of the grid while taking into consideration that, as technology advances, faster rates of compiling and measuring data will be increasingly available in the near future.

A common description of required data must be established for the whole interconnection so that the same data are available at the same rates and at the same time from all substations and the EMS control centers. The main criteria for determining what data are required should be such data that support grid reliability and adherence to reliability

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[43] *Available at* http://www.nerc.com/pub/sys/all_updl/standards/rs/TOP-006-0.pdf.

[44] A stand-alone subsystem that regulates the power output of electric generators within a prescribed area in response to changes in system frequency, tie-line loading, and the relation of these to each other. This maintains the scheduled system frequency and established interchange with other areas within predetermined limits.

[45] *See* 18 C.F.R. § 37.7 (requires that audit data must remain available upon request for download for three years from the date they were first posted on OASIS (Open Access Same-Time Information System)); 18 CFR § 125.3 Item 13.1 (d) and (e) require generating high-tension and low-tension load records and load curves, temperature logs, coal and water logs to be retained for three years; and 18 CFR § 125.3 Item 14 (a) and (b) require substation and transmission line logs and system operator’s daily logs and reports of operation to be retained for three years.

standards.[46]

Because substations are continually employing new measurement technologies to gather more accurate data at faster sampling rates, the uniform data requirements must continually be updated to keep pace. For example, faster sampling of currents and voltages with satellite-synchronized time stamping – in which both the value and the exact time of measurement are recorded – are being used increasingly to measure important system conditions such as phase angles, fault conditions, and switching sequences.[47] Similarly, improved communication is making these data rapidly available to distant computers. Faster computers are calculating more sophisticated measures of reliability than have been an option in the past. Combined, these features could enhance the level of real-time data available to the whole interconnection.

It is also important to understand which real-time data are currently archived by each transmission owner or operator and to determine the minimum data that must be stored to allow significant events affecting the power grid to be analyzed. This entails determining which data need to be stored and at what rates. For instance, it may not always be necessary to archive all of the data at the same rate as they are measured, especially when some quantities are being sampled many times a second, and others are sampled less frequently.

Another consideration is where the data should be archived. Two options are to store the data where they are generated or to store all of the data for the entire interconnection at one location. The goal is to have a data set available for analysis to answer reliability questions, such as whether a grid disturbance was caused by a single misoperation of equipment, by a series of events over a large area, or something in between. Having this data set available will address Recommendation Number 14 in the Final Blackout Report, which calls for establishing a standing framework for conducting future blackout and disturbance investigations. Archiving data in this manner will allow analysts to expedite a time-synchronized reconstruction of an event and facilitate investigations as proposed in Final Blackout Report Recommendation Number 14.[48]

Finally, it is necessary to address the extent to which common or standard formats and data base definitions are used for storing real-time data. Real-time data are often collected

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[46] NERC, *Approved Reliability Standards*, *available at* http://www.nerc.com/~filez/standards/reliability_standards.html.

[47] Voltage and current magnitudes are recorded as well as the time of measurement accurate to a millionth of a second. Fault conditions and switching sequence data can be used to reconstruct power system events in post-disturbance studies.

[48] Final Blackout Report, *supra* note 1, at 149.

and stored in different formats by the numerous SCADA/EMS vendors. This situation creates a major obstacle to automatically collecting and utilizing data from different parts of the interconnection, a critical function necessary for establishing an effective real-time transmission monitoring system.[49] Therefore, it is necessary to determine the commonality of all data outlined earlier in terms of format and exchange protocols and to determine the need for further development of standards for data conversion, collection, and sharing.[50]

Step 5. Identify Promising Emerging Technologies

While the SCADA and EMS systems are a useful foundation for a SCADA-based real-time monitoring system, advanced technologies show promise for establishing a more sophisticated system that could serve the future needs of users within the interconnections. Several such technologies are already being explored by the industry, while some technologies already exist but must be networked together to provide the technological sophistication required for an interconnection-wide real-time monitoring system. Therefore, the next step in the process should identify promising emerging technologies.

DOE has been funding research in Phasor Measurement Unit (PMU)[51] technology for more than 10 years.[52] PMUs are unique voltage and current transducers[53] that take time-synchronized measurements, which are important to the electric utility industry. PMUs use timing signals from the Department of Defense's Global Positioning System (GPS)[54] to precisely time-stamp voltages and currents at any geographic location on the power grid. The accuracy of PMUs is unparalleled, compared, for example, with that of traditional SCADA data, in which two voltage measurements taken from different points

[49] EPG Company, *SCADA System Assessment, available at* http://www.epgco.com/scada-system-assessment.html.

[50] An ANSI standard now exists for a common format for control center data, but not for all available substation and generation data. *See* Common Information Model (CIM) Standards, *available at* http://www.dmtf.org/standards/cim.

[51] A PMU, which is considered an IED is a modern fast transducer that provides synchronized phasor measurements of voltages and currents from widely dispersed locations in an electric power grid. *See* Appendix B, Glossary, for the definition of phasor measurement.

[52] *See, e.g.,* Eastern Interconnect Phasor Project, *available at* http://phasors.pnl.gov.

[53] A device which converts a measurement into a signal that can be monitored by the SCADA system.

[54] A satellite-based global navigation system that allows users to determine their exact location, velocity, and time, anywhere in the world, and in all types of weather.

on the bulk power grid may be "skewed" (or off) by as much as several seconds. SCADA would inaccurately record these two data points as one "scan" and log them into the database at one instant in time.

With a PMU, however, the time "skew" is never more than one-millionth of a second. PMU data sampling rates of as much as 60 times a second allow the calculation of voltage and current phase angles[55] along with power flows. The technical benefits of this technology include more accurate state-of-the-system estimates (which use metered data to estimate the status of the system in real-time),[56] better situational awareness and wide-area visibility for transmission system operators, and better post-disturbance analysis,[57] all of which contribute to better planning.

Currently, PMU technology is the basis for the Eastern Interconnection Phasor Project (EIPP), a DOE technology-transfer effort in which more than 40 system operators and reliability organizations across North America are participating. The purpose of this project is to install and network time-synchronized measurement units to make fundamental data widely available to grid operators for use in monitoring and visualizing system operations.

The Consortium for Electric Reliability Technology Solutions (CERTS)[58] has integrated and delivered three software applications based on phasor measurements. Operation support engineers at the California Independent System Operator Corporation (CAISO) are using these applications to study grid disturbances and calibrate system models that are used to develop guidelines for real-time operations, in coordination with the Western Electricity Coordinating Council.[59]

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[55] The measure of the progression of a periodic wave in time or space from a chosen reference or position.

[56] A state estimator is a computer software package that takes redundant measurements of system values and provides an estimate of system status. It is used to confirm that the monitored electric power system is operating in a secure state. A more comprehensive definition can be found in Appendix B, Glossary.

[57] Final Blackout Report, *supra* note 1, at 162, Recommendation Number 28.

[58] Consortium for Electric Reliability Technology Solutions, *available at* http://certs.lbl.gov.

[59] One of the 10 electric reliability councils in North America, encompassing a geographic area equivalent to half of the United States. It is responsible for promoting electric system reliability and providing a forum for coordinating the operating and planning activities of its 145 member systems. The members, representing all segments of the electric industry, provide electricity to 71 million people in 14 Western states, two Canadian provinces, and portions of one Mexican state.

CAISO is also pioneering the first-ever, real-time application of phasor technology in which phasor data collected by the Bonneville Power Administration, Southern California Edison, and Pacific Gas and Electric Company are being transferred to a CAISO data concentrator for use in prototype real-time monitoring workstations that are being built by CERTS.

While PMU technology is still in the development phase, many of the existing IEDs being used in today's utility substations could be networked together, using digital electronics, to form a fast (IED-based) real-time monitoring system to provide a complete picture of the power system "health." Such an IED-based system, therefore, could provide wide-area visibility necessary for real-time monitoring.[60]

Some existing IEDs that could be used for this purpose include the Digital Fault Recorder (DFR), which records a snapshot of voltages and currents at a substation during an abnormal event, such as a transmission line or a generator trip. The information from the DFR is used to examine and correct the performance of substation equipment. Many DFRs are now capable of streaming PMU data to data concentrators. A recorder records "what happened when" from hundreds of independent devices in a substation.[61] It is used to determine whether protection devices are triggered in the proper order to protect personnel and equipment. Another recorder, referred to as Dynamic Swing Recorder (DSR), is used to examine how power oscillations affect the system during periods of stress; the results are incorporated into planning studies and operating procedures to avoid excessive grid stress. Relays automatically perform protective action by switching equipment out of service in the event of serious abnormalities such as faults (i.e., short circuits). Some transmission line relays are now capable of streaming PMU data to concentrators.

Today there are a variety of electronic devices[62] that could be utilized in an interconnection-wide real-time monitoring system. However, there is no need to rely on a single technology to provide all of the information required to adequately monitor real-time information on the functional status of all transmission lines. In fact, multiple monitors are actually desirable, as they could provide redundancy to enhance reliability.

Currently, the phasor projects in both the Eastern and Western Interconnections are using

[60] Electric Power Research Institute, *Distribution Design to Integrate New Intelligent Electronic Devices, available at* http://www.epri.com/portfolio/product.aspx?id=1499&area=38&type=10.

[61] Referred to by industry as a Sequence of Events Recorder.

[62] Other options include condition monitors that detect various special circumstances such as circuit breaker failure, over-temperature, and oil contamination, as well as meters that monitor and record billing and accounting quantities.

concentrators that collect and store data from PMUs in a database at each utility. These data are archived at a central concentrator. Software at the central concentrator continuously processes the data streaming in from across the interconnection and creates a graphic visualization of grid status, which is available to NERC RCs and grid operators via secure internet communications. However, future use of these data to control the grid flexibly in real time would require a communication network structure that can move the data in a timely, secure manner.

The number of phasor measurements could increase dramatically in the future as more PMUs are added. Use of phasor data in real time across an interconnection will challenge any communication architecture, but the ability to use these data in real time will greatly enhance operators' ability to run the grid reliably and securely.

Step 6. Decide what Data Should be Shared, with Whom, and When

Should an interconnection-wide real-time monitoring system be pursued, the next step in the process could be identifying what information should be shared, at what frequency, and among which entities.

The majority of real-time data is private and contains sensitive operational information (e.g., generator and transmission line status). From a security perspective, it is important that the monitoring system ensure that the private data is only shared among entities with legitimate credentials. This would include the entities that have signed a data confidentiality agreement. Another important security measure is to ensure that the data cannot be manipulated and that any remote control functions cannot be exercised by unauthorized users. Further, frequency of updates and a hierarchy of needs for specific information should be addressed, as these requirements vary for different users. For instance, entities such as BAs, RCs and the ERO would likely require more detailed information and more frequent updates on day-to-day operations than government entities such as the Commission or DOE. However, government entities would likely require that historical data be available to government entities[63] to facilitate investigation and assessment of conditions as necessary, such as those that result in reliability violations, or crisis situations[64] as part of post-disturbance analysis as identified by Recommendation Number 14 of the Final Blackout Report.[65]

[63] EPAct 2005 recognizes the international footprint of the North American electric transmission system by acknowledging Canadian and Mexican interests in the reliability of the interconnected North American electric grid. *See* EPAct 2005 § 1211, 119 Stat. 594, 941 (2005).

[64] Final Blackout Report, *supra* note 1, at 149, Recommendation Number 14.

[65] *Id.*

Further, a technical process for identifying critical transmission paths and equipment would be a necessary component of this step. In both the Eastern and Western Interconnections, certain generators, transmission paths, substations, and/or regions are known to be critical for the reliability of the interconnections. However, critical facilities change over time as new generation, transmission or other equipment is added and power flow patterns change.

Once a system is established where real-time information can be gathered, archived, and shared, the next logical step is to determine who should have access to this data. The criterion for access should be an entity's "need to know" for the purpose of ensuring monitoring, assessing, investigating, and/or enforcing reliability. For example, the Commission and the ERO will likely need access to all data while a transmission owner may only need data from its nearest neighbors or from those that may have an impact on its service.

In addition to resolving the data-sharing issues addressed above, system designers must also determine the amount of monitoring necessary for real-time functional status reporting. The level of monitoring will depend upon the number and location of measurements needed to cover key corridors and system sites in order to perform reliability functions and to provide all users with sufficient information to monitor the functional status of all transmission lines within the interconnections.

Another area that should be addressed involves the types of processes needed to share data among entities. Here, a distinction must be made between sharing the real-time data and sharing the historical data. For instance, SCADA real-time monitoring may be configured to be updated once every two minutes for overall monitoring of system integrity by an operating entity, whereas historical data should be available at the same rate that it was originally created and archived in order to accurately analyze and simulate past events.

Because of the limitations of current monitoring technology described in Step 2 above, some changes would be required in existing SCADA and EMS systems to allow for efficient data-sharing with the real-time monitoring system. The changes will require the use of the Common Information Model.

Step 7. Decide Who Should Operate, Use, and Maintain the System

Moving from system-related issues to organizational issues, should a real-time transmission monitoring system be pursued, the next step would be to categorize the roles, responsibilities, and tools provided to reliability desks in the EMS control centers throughout the interconnections.

The roles and responsibilities of reliability desks in the control centers throughout the interconnections include monitoring the real-time status of bulk power system components in their areas, monitoring the status of communication equipment, and monitoring data quality. If local communication equipment that is a part of the transmission line monitoring system is not functioning properly, the control center should notify all other EMS control centers that use the transmission line monitoring system. Likewise, if data coming in from local equipment are corrupt, all transmission monitoring system users should be notified of the problem. This will help those using the system to know whether information coming from the monitoring system is based on accurate measurements.

The tools provided to reliability desks in the control centers throughout the interconnections include visualization tools and data about neighboring systems. Visualization tools could show information about the entire interconnection (e.g., voltage and frequency) and also have dynamic zoom capability to show information about a specific area. A good visualization system quickly summarizes computer data for operator action.

The data provided by visualization systems could also enhance grid reliability. Visualization systems could be integrated into state estimators and, along with other contingency analysis software, allow a system operator to review each critical contingency to determine whether each possible scenario is within reliability limits. Neighboring system information also could be integrated into security analysis tools, which help operators analyze what steps to take if different outages occur, based on the current system state.

Step 8. Identify Potential Participants Involved in Establishing a Real-Time Monitoring System

If a transmission monitoring system is to be established, another step in the process would be identifying potential participants and understanding the needs of these users. Potential participants in establishing a real-time transmission monitoring system include the ERO, regional entities, transmission entities, the Commission, DOE, Canadian and Mexican agencies,[66] provincial regulators, and state regulators. Each would likely have a role in collaboratively maintaining and/or utilizing the data infrastructure, with the goal of ensuring reliable operation of the electric grid.

Different participants would have different needs for transmission line monitoring information. The ERO and the Commission, as well as DOE, Canadian, Mexican, and other agencies, would likely need to see all transmission lines in the interconnections. State and Provincial governments may only need to see transmission lines within their State or Province along with the lines outside of the State or Province that may impact

[66] In Mexico, the equivalent state regulator is called Comision Reguladora de Energia.

their system(s). Individual utilities may need to see an entire interconnection or just a small area. The entity developing visualization software would need to understand and address these needs.

As new transmission lines are built, the ERO could take steps to ensure that compatible monitoring and communication equipment are installed in the monitoring system. Likewise, as technology evolves, new communication infrastructure, software, and/or metering may need to be installed to maintain a state-of-the-art monitoring system.

Step 9. Consider Cost and Funding Issues

The final step prior to implementation of the real-time monitoring system would be to consider cost and funding issues. The system's cost would depend on the level of technology and infrastructure that are currently in place for that entity. For example, an entity that has already installed digital equipment (i.e., digital relays) could more easily upgrade to a better sophisticated IED at a cost less than an entity that lacks these modern devices.

Further, in addition to the development and deployment of the system, the total cost would include maintenance and upgrades throughout the system's life.

The variety of choice in configurations is a positive development for the industry. While the first eight years of technology development in the area of time-synchronized recording equipment for the power industry saw few commercial product lines, there are now more commercial manufacturers of this type of equipment. The Institute of Electrical and Electronic Engineers (IEEE), a professional society representing power engineers, has approved several standards ensuring compatibility of equipment and data.[67] The vendor community now offers a variety of configurations to suit the needs of the most common utility environments. The time-synchronized recording device could be purchased as optional equipment on standard transmission line relays, as optional equipment on digital fault recorders, as stand-alone units, or in a number of alternative packages.

The sources of funding and their mechanisms should also be addressed. Depending on the benefits accruing to the parties involved, funds for development, deployment, and maintenance of the monitoring system could come from Congressional appropriations, a supplemental tariff on transmission, and/or directly from the transmission owners, or from recovery of costs necessary to comply with reliability standards pursuant to the reliability provisions of EPAct 2005 should such standards be implemented.[68]

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[67] IEEE Standard 37.118-2005, Standard for Synchrophasors for Power Systems, approved by IEEE Board but not yet published.

[68] EPAct 2005 § 1241, 119 Stat. 594, 961-62. New § 219(6)(4) of the FPA requires the

Section III. Steps to Implement an Interconnection-Wide Real-Time Monitoring System

Section 1839 also requires that this Joint Report ". . . identify the steps the Commission or Congress must take to require implementation of such system."[69] DOE and the Commission have identified two steps that could be followed if an interconnection-wide real-time monitoring system is to be implemented.

Step 1. Research and study efforts to determine feasibility, cost, and benefits of a real-time transmission monitoring system for the Eastern and Western Interconnections.

Step 2. Based on the findings from Step 1 above, possible development of real-time monitoring system reliability standards.

Step 1. Research and Study Efforts

The Commission, in coordination with DOE, could request that the ERO research and study, for review, a workable technical and financial approach to establishing a real-time transmission monitoring system for the Eastern and Western Interconnections. As a practical measure, it would be necessary to obtain feedback from all stakeholders. The ERO report would need to be developed using technical conferences, industry meetings, and independent studies. The ERO would coordinate the efforts involved in this task.

Ultimately, the feasibility of implementing an interconnection-wide real-time monitoring system would depend on the outcome of a cost-benefit analysis. For example, one of the principal causes of the August 2003 blackout was a lack of situational awareness of operators, a problem that an interconnection-wide real-time monitoring system could address. Although this was not the only cause of the blackout, and its mitigation would not have prevented the event, the cost of that blackout was $4 billion to $10 billion.

Step 2. Possible Development of Real-Time Information Monitoring Reliability Standards

The findings of the ERO study should provide a basis necessary for determining the next

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Commission to establish a rule, among other things, allowing recovery of "all prudently incurred costs necessary to comply with mandatory reliability standards."

[69] EPAct 2005 § 1839, 119 Stat. 594, 1142 (2005).

steps in the implementation phase of an interconnection-wide real-time monitoring system. This information should also be used to determine whether an interconnection-wide real-time monitoring system should be implemented. If it is determined that such a system is feasible, the development of mandatory reliability standards by the ERO may be the most effective way forward. In addition, if such standards are to be pursued, the requirements to be considered include but are not limited to the following: specifications of the monitoring equipment, type of information to be provided and to whom, communication specifications.

Should such standards be developed, pursuant to EPAct 2005's provisions, the Commission could either approve the proposed reliability standards or remand them for further consideration.[70]

[70] *Id.* at § 1211, 119 Stat. 594, 943.

Section IV. Conclusion and Recommendations

This report to Congress identifies the steps necessary to establish and implement a real-time transmission monitoring system for the Eastern and Western Interconnections, but does not pre-judge the feasibility of such an endeavor. In addition to the requirements set out by Congress, this report includes relevant findings and recommendations from the Final Blackout Report, and identifies steps to establish and implement an interconnection-wide real-time monitoring system.

The analysis concludes that current technologies could provide a foundation for establishing a SCADA-based real-time information system, but we must look to advanced technologies to fully respond to recommendations in the Final Blackout Report. The findings from technical analysis in this joint report for establishing a real-time information monitoring system are described in the recommendations below.

Should such a system be implemented, a phased implementation of a combination SCADA-based system and a fast (IED-based) system is recommended. Further, the planning for Phase II should begin at the same time Phase I is being designed.

The SCADA-based real-time information system could be assembled using the existing SCADA/EMS infrastructure architecture and components with some changes in data communications. The issues with non-standard data structures and data exchange would have to be addressed by using the established standards and methods. The database structure for storing the SCADA/EMS real-time and historical data may be completely different at each control center. The Common Information Model standards could be adopted to address this issue by ensuring data consistency and efficiency.

In terms of data sharing, the use of a publish-and-subscribe communication architecture and the concept of data concentrators appear to be feasible methods in providing a systematic approach for organizing and sharing the massive amounts of real-time data among various entities. Another issue that would need to be addressed for the SCADA-based system is system security. While the existing communication has been developed with built-in security, in today's interconnected environment, additional security measures are critical for enabling uninterrupted operations for transmission, generation, and ISOs.

The fast IED-based real-time information system is under accelerated development in response to the Final Blackout Report, with operating prototype systems in the Eastern and Western Interconnections. Recommendation Number 28 of the Final Blackout Report requires the industry to use time-synchronized data recorders.[71] All time-synchronized data recorders (i.e., digital fault recorders, digital events recorders, phasor measurement units,

[71] Final Blackout Report, *supra* note 1, at 162.

and power system disturbance recorders) are time-stamped at the point of observation using a Global Positioning System (GPS) synchronizing signal. Time-synchronized devices, such as phasor measurement units, could be beneficial for providing a wide-area view of power system conditions in real-time. The fast (IED-based) real-time information system would collect real time data from time-synchronized data recorders to provide instant transmission system visibility across the interconnection, and provide the capability for quick post-disturbance analysis. These systems would operate separately in parallel with the SCADA-based system to provide the full range of required data.

The Final Blackout Report found that a "lack of situational awareness" was a "principal cause" of the interruption of power to over 50 million citizens of the United States and Canada, causing an estimated cost of between $4 billion and $10 billion to the nation.[72] To address this problem, the Commission and DOE have found that the technology necessary to implement a real-time transmission monitoring system does exist at present and could be utilized to improve the reliability of the nation's bulk power system by increasing the situational awareness of the transmission entities, as recommended in the Final Blackout Report, thereby addressing one of the "principal causes"[73] of the blackout. In addition, new technologies hold the promise of greatly enhancing both situational awareness and system automation, thereby further reducing the possibility of regional and interregional blackouts.

This report recommends that the Commission, in consultation with DOE, request the newly established ERO that is certified by the Commission pursuant to section 215 of the Federal Power Act,[74] to investigate and report on the feasibility, cost, and timeline to establish the monitoring system. The ERO report is expected to be developed using technical conferences, industry meetings, and independent studies. The analysis from the ERO will be used to: (1) determine whether the implementation of a real-time monitoring system is feasible; and (2) if feasible, develop mandatory reliability standards necessary for the implementation of such a system.

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[72] *Id*. at 1.

[73] *Id.* at 159, Recommendation Number 22.

[74] EPAct 2005 § 1211, 119 Stat. 594, 941-46.

Appendix A
Acronyms

ACE	Area Control Error
AGC	Automatic Generation Control
ANSI	American National Standards Institute
API	Application Program Interface
ATC	Available Transfer Capability
BA	Balancing Authority
CAISO	California Independent System Operator
CERTS	Consortium for Electric Reliability Technology Solutions
CIM	Common Infrastructure Model
Commission, the	Federal Energy Regulatory Commission
CRC	Central Repository for Security Events
DCS	Distributed Control System
DFR	Digital Fault Recorder
DOE	Department of Energy
DSR	Dynamic Swing Recorder
EIPP	Eastern Interconnection Phasor Project
EMS	Energy Management System
EPRI	Electric Power Research Institute
ERO	Electricity Reliability Organization
FERC	Federal Energy Regulatory Commission (Commission)
FPA	Federal Power Act
GPS	Global Positioning System
HV	High Voltage
ICCP	Inter-Control Center Communications Protocol
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronic Engineers
ISO	Independent System Operator
kV	Kilo-volt
LMP	Locational Marginal Price
NERC	North American Electric Reliability Council
PDC	Phasor Data Concentrator
PMU	Phasor Measurement Unit
QoS	Quality of Service
RC	Reliability Coordinator
RTO	Regional Transmission Organization
RTU	Remote Telemetry Unit
SCADA	Supervisory Control and Data Acquisition

SDX	System Data Exchange (NERC)
SER	Sequence of Events Recorder
TCP/IP	Transmission Control Protocol/Internet Protocol
TLR	Transmission Loading Relief
TO	Transmission Operator

Appendix B
Glossary of Terms

Application Program Interface (API): An application program interface is the software interface to system services or software libraries. An API can consist of classes, function calls, subroutine calls, and descriptive tags.

Area Control Error (ACE): The instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including a correction for meter error.

Automatic Generation Control (AGC): A stand-alone subsystem that regulates the power output of electric generators within a prescribed area in response to changes in system frequency, tie-line loading, and the relation of these to each other. This maintains the scheduled system frequency and established interchange with other areas within predetermined limits.

Available Transfer Capability (ATC): A measure of the transfer capability remaining in the physical transmission network between a specific point of delivery and point of receipt over and above already committed uses.

Balancing Authority, formerly known as Control Area (BA): The entity responsible for balancing load and generation in real time in its Balancing Authority area. For example, the New York Independent System Operator is the Balancing Authority for the state of New York. A Balancing Authority area is an electric system bounded by interconnection metering and telemetry, which measure the current, voltage, power flow, and status of transmission equipment.

Capacitor: A device that stores electrical charges and can be used to maintain voltage levels in power lines and improve electrical-system efficiency.

Common Information Model (CIM): A common definition of management information for systems, networks, applications and services, and allows for vendor extensions. CIM's common definitions enable vendors to exchange semantically rich management information between systems throughout the network.

Consortium for Electric Reliability Technology Solutions (CERTS): An organization formed in 1999 to research, develop, and disseminate new methods, tools, and technologies to protect and enhance the reliability of the U.S. electric power system and functioning of a competitive electricity market.

Control Center: The operational center for SCADA and EMS where the state of the system is monitored.

Current Transducer: A device that converts a current measurement into a signal that can be monitored by a SCADA system.

Cyber Security: The branch of Security dealing with digital or information technology.

Data Concentrator: A collection of streamed information stored in a computer in a systematic way.

Digital Fault Recorder (DFR): An intelligent electronic device that records a snapshot of voltages and currents at a substation during an abnormal event. The recording is performed at a very high sampling rate.

Distributed Control System (DCS): A computer-based control system where several sections within the plants have their own processors, linked together to provide both information dissemination and manufacturing coordination.

Eastern Interconnection Phasor Project (EIPP): Technology-transfer effort sponsored by DOE in cooperation with utilities, RTOs, ISOs, hardware and software vendors, and NERC to develop and deploy a real-time, wide-area measurement network in the Eastern Interconnection.

Energy Management System (EMS): A computer control system used by electric utility dispatchers to monitor the real-time performance of various elements of an electric system and to control generation and transmission facilities.

Electricity Reliability Organization (ERO): The Energy Policy Act of 2005 contains reliability provisions that authorize the creation of a self-regulatory electric reliability organization (ERO) that covers the United States excluding Alaska and Hawaii, with Commission regulatory oversight.

Global Positioning System (GPS): A satellite-based global navigation system that allows users to determine their exact location, velocity, and time, anywhere in the world, and in all types of weather.

Inter-Control Center Communications Protocol (ICCP): An international standard for real-time data communication between the EMS control centers, utilities, power pools, regional control centers, and non-utility generators. ICCP defines a set of objects and services for data exchanging.

Intelligent Electronic Device (IED): This device monitors grid operational parameters and is capable of independent protective action at the substation level. Some examples of IEDs are Digital Fault Recorders (DFRs) and SERs Sequence of Events Recorders (SERs).

Independent System Operator (ISO): An entity approved by the Commission - (a) to exercise operational or functional control of facilities used for the transmission of electric energy in interstate commerce; and (b) to ensure nondiscriminatory access to the facilities.

Kilovolt (kV): Unit of electrical potential equal to 1,000 Volts.

Middleware: A communications layer that allows applications to interact across hardware and network environments.

Non-utility Generator: A power plant (or its owners) not owned by the utility to whose retail customers the output is sold. It is also called an Independent Power Producer.

North American Electric Reliability Council (NERC): A not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of nine Regional Reliability Councils and one Affiliate, whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja-California-Norte-Mexico. The members of these regional councils are from all segments of the electricity supply industry: investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers. The NERC Regions are: East Central Area Reliability Coordination Agreement (ECAR); Electric Reliability Council of Texas (ERCOT); Mid-Atlantic Area Council (MAAC); Mid-America Interconnected Network (MAIN); Mid-Continent Area Power Pool (MAPP); Northeast Power Coordinating Council (NPCC); Southeastern Electric Reliability Council (SERC); Southwest Power Pool (SPP); Western Systems Coordinating Council (WSCC); and Alaskan Systems Coordination Council (ASCC, Affiliate). NERC has developed the Version 0 reliability standards.

NERC System Data Exchange (NERC SDX): Provides a central repository of all scheduled and on-going branch, generator, and transformer outages throughout the Eastern Interconnection. This data is made available to NERC-approved users, who have agreed to the terms of the NERC Data Confidentiality Agreement.

Phase Angle: The measure of the progression of a periodic wave in time or space from a chosen reference or position.

Phase Shifter: A device used to control the power flow within a given network by creating a angle shift between its primary and secondary terminals.

Phasor Data Concentrator (PDC): A computer database that contains data from several phasor measurement units (PMUs).

Phasor Measurement: Simultaneous measurement of network voltage and current phasors (i.e., magnitudes and angles) at different geographical locations of the network through GPS time stamping.

Phasor Measurement Unit (PMU): A modern fast transducer that provides synchronized phasor measurements of voltages and currents from widely dispersed locations in an electric power grid.

Power Pool: Two or more electric systems that are interconnected and operated on a coordinated basis to promote economies of scale as well as reliability in supplying their combined loads.

Quality of Service (QoS) Requirements: Require that communication for the power grid be delivered in a timely, reliable manner with adequate bandwidth.

Regional Transmission Organization (RTO): An entity of sufficient regional scope approved by the Commission - (a) to exercise operational or functional control of facilities used for the transmission of electric energy in interstate commerce; and (b) to ensure nondiscriminatory access to the facilities.

Reliability Coordinator (RC): An organization responsible for the safe and reliable operation of the interconnected transmission system for its defined area, in accordance with NERC reliability standards, regional criteria, and sub-regional criteria and practices. This entity facilitates the sharing of data and information about the status of the BA for which it is responsible, establishes a security policy for these BAs and their interconnections, and coordinates emergency operating procedures that rely on common operating technology, criteria, and standards.

Remote Telemetry Unit (RTU): A device that collects data at a remote location and transmits it to a central station. RTUs are commonly used in SCADA systems.

Supervisory Control and Data Acquisition (SCADA): A computer system for gathering and analyzing real time data. SCADA systems are used to monitor and control a plant or equipment.

Security Analysis: Use of computer software to analyze system contingencies to ensure that power can be delivered from generation to load within the operating limits of transmission equipment and without loss of continuity of supply or widespread failure for the most likely contingencies.

Sequence of Events Recorder (SER): An intelligent microprocessor-based system that records remotely occurring events.

Situational Awareness: The ability to identify, process, and comprehend information about what is happening in a complex system; specifically, the ability to understand real-time power system operation with regards to reliability.

Stability Limit: The maximum power flow possible through a particular point in a system while maintaining stability in the entire system. A stability limit can also apply to a local area of the system.

State Estimator: Computer software package that takes redundant measurements of quantities related to system state as input and provides an estimate of the system state. It is used to confirm that the monitored electric power system is operating in a secure state by simulating the system both at the present time and one step ahead, for a particular network topology and loading condition. With the use of a state estimator and its associated contingency analysis software, system operators can review each critical contingency to determine whether each possible future state is within reliability limits.

Status Variable: Periodic sequence of time-stamped values corresponding to measurement, condition, or control settings in the power grid.

Substation: Facility equipment that switches, changes, or regulates electric voltage and power flow.

Supervisory Control and Data Acquisition (SCADA): A system of remote control and telemetry used to monitor and control the electric system. SCADA is also used in other industries, including chemical plants and water treatment facilities.

Telemetry: Transmittal and receiving of electronic data over long-distance communication links.

Time Stamp: Information added to data to indicate the time at which it was recorded.

Transformer: A device used to raise or lower voltage in an electric transmission system.

Transmission Control Protocol/Internet Protocol (TCP/IP): A protocol for transmitting data between computers, the basis for standard internet protocols.

Transmission Line: Facility for transmitting electrical power at high voltages. For purposes of this report, transmission lines are those at 69 kV and higher.

Transmission Loading Relief (TLR): A NERC procedure used to manage congestion on the electric transmission system. The TLR procedure is invoked by the RC to alleviate an overload condition detected on transmission lines in its jurisdiction.

Transmission Operator (TO): NERC-certified party (company) responsible for monitoring and assessing local reliability conditions; operates the transmission facilities and executes switching orders in support of the Reliability Authority.

Transmission System: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Utility: A company that provides and manages energy and is subject to state and federal government regulation.

Visualization: Methods of displaying data, including lists, tables, charts, and graphics.

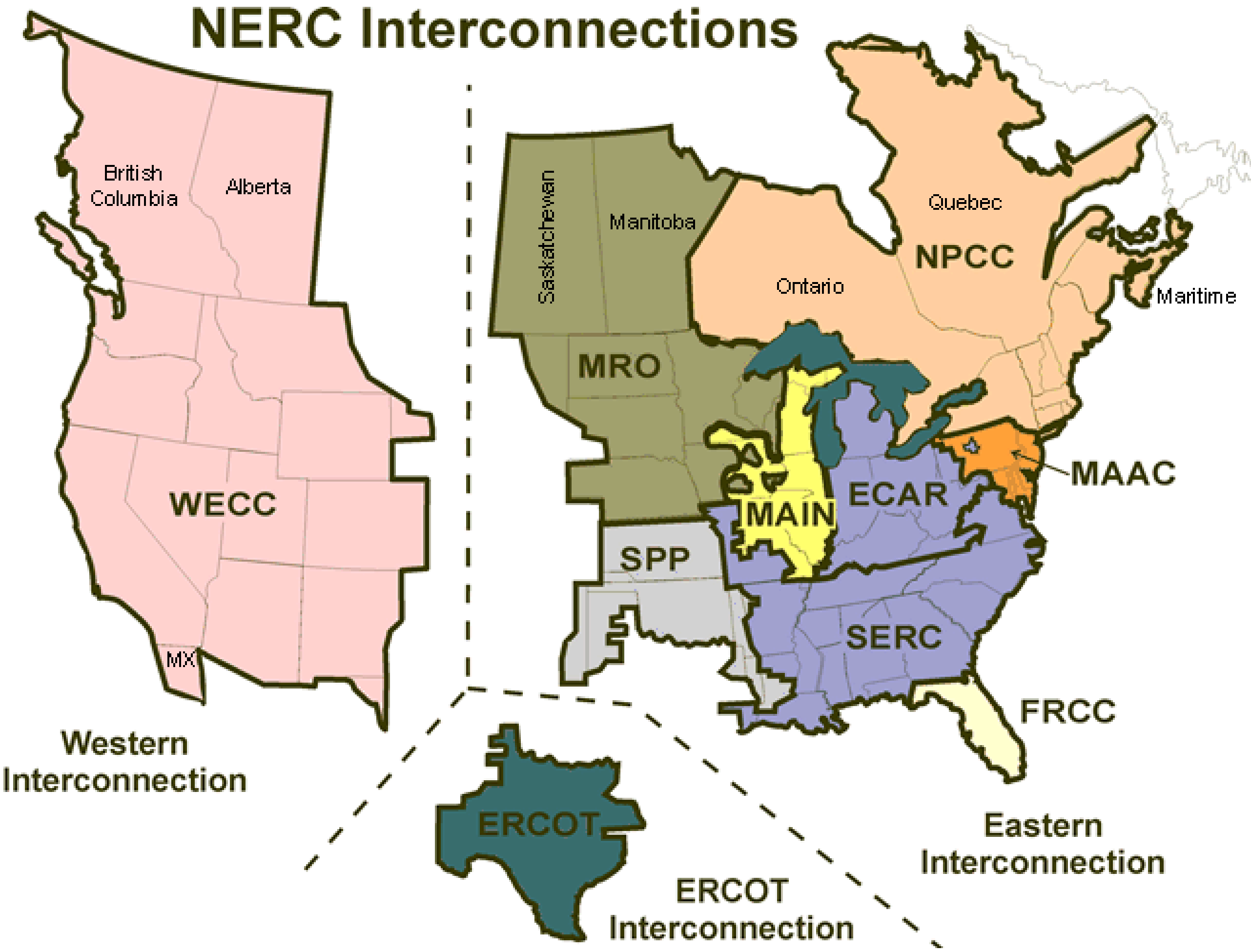
Voltage: The electrical force or "pressure" that causes current to flow in a circuit, measured in Volts.

Voltage Limit: A hard limit above or below which is an undesirable operating condition. Normal limits are between 95 and 105 percent of the nominal voltage at the point under discussion.

Voltage Stability: The condition of an electric system in which the sustained voltage level is controllable and within predetermined limits.

Voltage Transducer: A device that converts a voltage measurement into a signal that can be monitored by a SCADA system.

Appendix C
Geographical Boundaries of Interconnections



North American Electricity Reliability Council, *available at* http://www.nerc.com/regional.

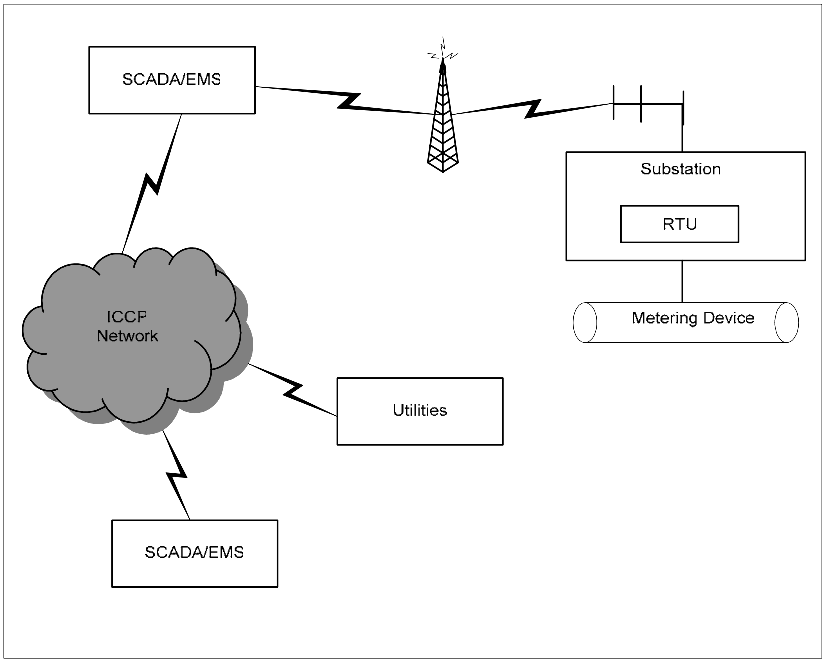
Appendix D
Functional Status Matrix

<table>
<tr><th colspan="10">Organizational Source of Real-Time Information</th></tr>
<tr><th></th><th>SCADA</th><th>Transmission Operator via ICCP from TO SCADA</th><th>RTO/ISO via ICCP from TO SCADA</th><th>NERC CRC</th><th>NERC SDX</th><th>Derived Information (derived in RTO or TO EMS from TO SCADA)</th><th>Time-Synchronized Data Recorders (PMUs)</th><th>Intelligent Electronic Devices (DFRs, SERs, DSRs)</th><th>Functional Application for Data (Real-time applications emphasized)</th></tr>
<tr><td>Functional Status</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Switching Status (topology)</td><td rowspan="3">X</td><td>X</td><td>X</td><td></td><td>X</td><td></td><td></td><td></td><td>Used for state estimation, operator displays, confirmation of operator-initiated switching actions, SCADA alarm processor</td></tr>
<tr><td>Real/Reactive Power Flow</td><td>X</td><td>X</td><td></td><td></td><td></td><td>X</td><td></td><td>Used for state estimation, operator displays, alarm processor</td></tr>
<tr><td>Voltage Magnitude</td><td>X</td><td>X</td><td></td><td></td><td></td><td>X</td><td></td><td>Used to dispatch reactive resources, primarily capacitors</td></tr>
<tr><td>Voltage Angle</td><td></td><td></td><td></td><td></td><td></td><td></td><td>X</td><td></td><td>May indicate system stress</td></tr>
<tr><td>Line Sag</td><td>X</td><td>X</td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Phase Angle Rate-of-Change</td><td></td><td></td><td></td><td></td><td></td><td>X</td><td>X</td><td></td><td>May indicate potential islanding or impending system separation</td></tr>
<tr><td>Tap Changer/Phase Shifter Setting</td><td></td><td>X</td><td>X</td><td></td><td></td><td></td><td></td><td></td><td>Used for state estimation and for certain derived information calculations</td></tr>
<tr><td>Interconnection Frequency</td><td></td><td></td><td>X</td><td></td><td></td><td></td><td>X</td><td></td><td>Used in ACE calculations resulting in AGC action. Also indicator of grid stress</td></tr>
<tr><td>Limit Violation Monitoring (flow, voltage, stability)</td><td></td><td></td><td></td><td></td><td></td><td>X</td><td></td><td></td><td>Some limits are determined in advance through planning studies while some are calculated in real time</td></tr>
</table>

Organizational Source of Real-Time Information										
Functional Status	SCADA	Transmission Operator (via ICCP from TO SCADA)	RTO/ISO (via ICCP from TO SCADA)	NERC CRC	NERC SDX	Derived Information (derived in RTO or TO EMS from TO SCADA)	Time-Synchronized Data Recorders (PMUs)	Intelligent Electronic Devices (DFRs, SERs, DSRs)	Functional Application for Data (Real-time applications emphasized)
ATC						X			
TLR Status				X		X			
LMP						X			While not strictly an engineering quantity, LMP affects flows and system operation
Security Alarms		X							Primarily door switches to alert operators when someone enters a substation control house
Other SCADA Analogs	X	X	X						Oil temperature, wind speed, line sag, etc.
Application Calculation Results						X			Applications may include dynamic security assessment, dynamic line rating, ATC, LMP, TLR, etc.
Dynamic Disturbance Data							X	X	SER, DFR, DSR, etc. not currently used in real-time
Post Disturbance Analysis		X	X			X	X	X	Requires robust archival capability of real-time data

Compiled by Commission and DOE Staff

Appendix E
SCADA and EMS Communications

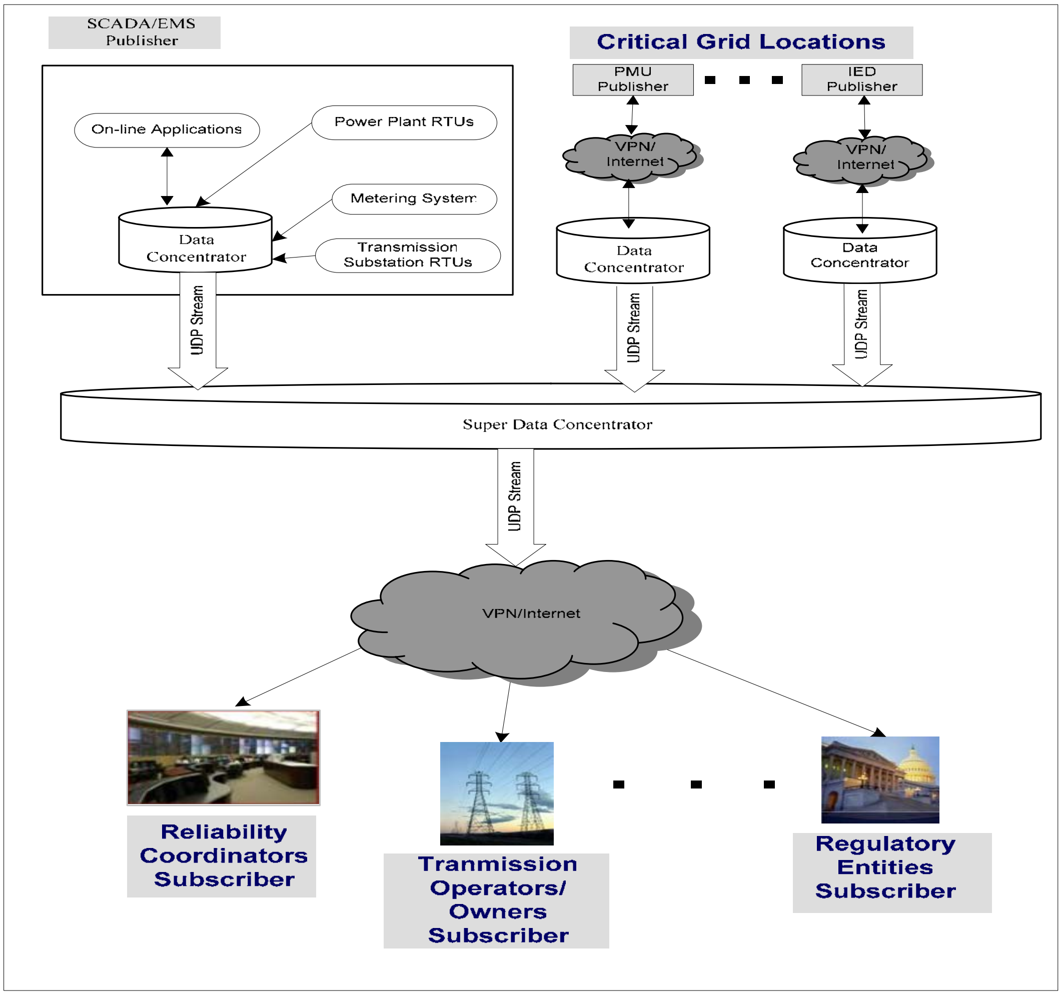


Measurements from metering devices on transmission equipment and in substations are collected by an RTU, which sends data to a utility SCADA/EMS system. ICCP network allows different utilities to share SCADA/EMS data.

Compiled by Commission Staff

Appendix F
Proposed Transmission System Monitoring Data Communications Infrastructure

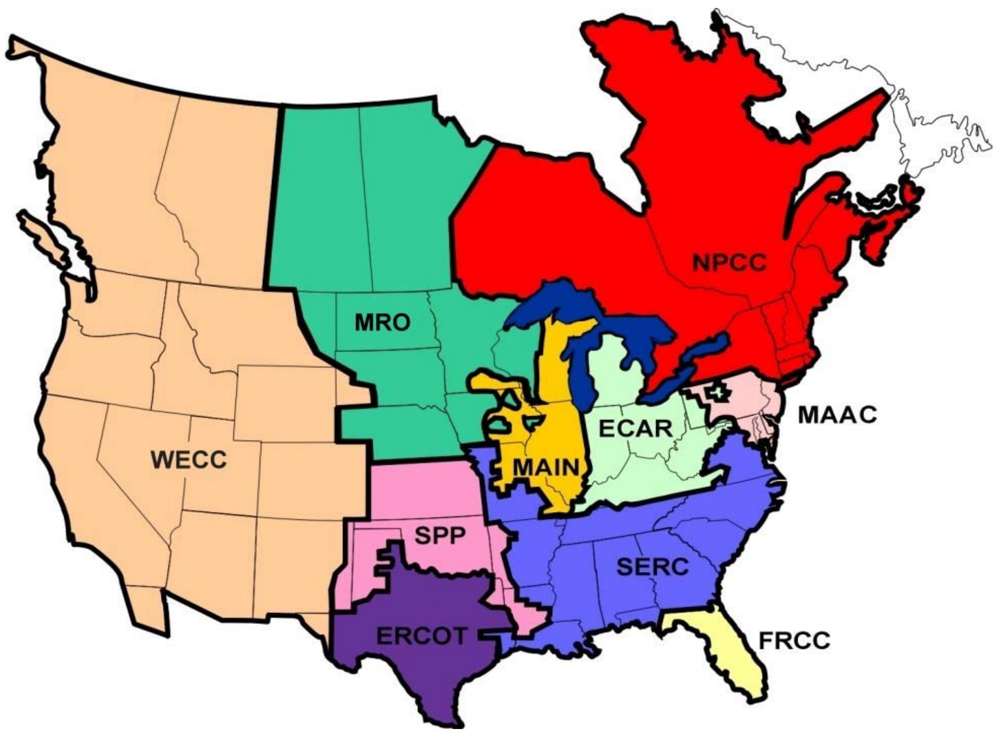
The figure below shows the proposed infrastructure for transmission monitoring system data communications using the publisher/subscriber methodology.



Compiled by Commission Staff

Appendix G

Map of NERC Regional Reliability Councils



North American Electricity Reliability Council, *available at* http://www.nerc.com/regional.