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## U.S. – Canada Power System Outage Task Force

# Final Report on the Implementation of Task Force Recommendations

**, 2006**

# Acknowledgements

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# 1. Introduction

*[To be written following the June 22, 2006, Conference for Public Review.]*

## 2. Background

On August 14, 2003, the largest power blackout in North American history affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut and New Jersey, and the Canadian province of Ontario.

Beginning a few minutes after 4:00 p.m. Eastern Daylight Time (16:00 EDT), the blackout left some parts of the United States without power up to four (4) days. Though all of Ontario customers' supply was restored within two (2) days, many customers responded to the Ontario Government's appeal to reduce consumption by 50% during the following work week. The power supply was restored to normal and restored to all Ontario customers by August 22, 2003. Estimates of the total costs caused by the blackout in the United States ranged between $4 billion and $10 billion (U.S. dollars). In Canada, the gross domestic product was down 0.7% in August, there was a net loss of 18.9 million work hours, and manufacturing shipments in Ontario were down $2.3 billion (Canadian dollars).

On August 15, 2003, President George W. Bush of the United States and then Prime Minister Jean Chrétien of Canada directed that a joint U.S. - Canada Power System Outage Task Force (Task Force) be established to investigate the causes of the blackout and ways to reduce the possibility of future outages. They named the U.S. Secretary of Energy and the Canadian Minister of Natural Resources to chair the joint Task Force. An additional three U.S. representatives and three Canadian representatives were also named to the Task Force. The U.S. members were the Secretary of Homeland Security, the Chairman of the FERC, and the Chairman of the NRC. The Canadian members were the Minister of Public Safety and Emergency Preparedness, the Chairman of the National Energy Board, and the President and CEO of the Canadian Nuclear Safety Commission.

The mandate of the joint Task Force was to a) investigate the outage to determine its causes and why it was not contained, and b) develop recommendations to reduce the possibility and scope of future outages.

The Task Force created three working groups to assist in both phases of its work—the Electric System Working Group, the Nuclear Working Group, and the Security Working Group. The working groups were made up of representatives of the affected states and Ontario, federal employees, and contractors working for the U.S. and Canadian government agencies represented on the Task Force. To aid in investigating the causes of the blackout and in developing the Task Force's recommendations, a team was created comprised of electricity experts from the three working groups as well as government agencies in the United States and Canada, the North American Electric Reliability Council (NERC) and the electricity industry.

The Task Force published an Interim Report on November 19, 2003, summarizing the facts that the bi-national investigation found regarding the causes of the blackout.[1] Public meetings were organized and held in Cleveland, New York City and Toronto. Technical conferences were held in Philadelphia and Toronto in December 2003 and January 2004, respectively.

NERC played an important role in the Task Force's investigation of the outage and, as a result of the findings of the investigation, the NERC Board of Trustees approved, on February 10, 2004, a series of actions intended to improve the reliability of the North American bulk power system.[2] The NERC Board of Trustees' statement is annexed to the Final Blackout Report of the Task Force.

The Task Force investigation included a review of previous major North American power outages. This review found that the causes of the August 14, 2003, blackout were strikingly similar to those of earlier outages.[3] This finding reinforced the need to monitor the effective implementation of the Task Force's recommendations. As a result, the governments of the United States and Canada extended the Task Force's mandate by one year in order to underscore the two governments' commitment of ensuring that the recommendations are acted upon.

The co-chairs of the Task Force submitted the Final Blackout Report to the President of the United States and Prime Minister of Canada in April 2004. The Final Blackout Report identified the causes of the blackout and included 46 recommendations on actions needed by government and industry, many of which include several elements. The recommendations were developed by the three working groups with input from experts, the public, NERC, members of Regional Reliability Councils and the electric power industry. The recommendations were accepted and endorsed by the Task Force to improve grid reliability and mitigate the possibility of future blackouts. On the first anniversary of the blackout, August 14, 2004, a report prepared for the Task Force was released and summarized the many actions taken by governments, the reliability organizations and the bulk power industry to reduce the risk of future blackouts.[4]

[1] U.S. – Canada Power System Outage Task Force, Interim Report: Causes of the August 14th Blackout in the United States and Canada (November 2003).
[2] August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, February 10, 2004, http://www.nerc.com/~filez/blackout.html.
[3] Final Blackout Report, p. 103.
[4] Report to the U.S. and Canada Power System Outage Task Force, The August 14, 2003, Blackout One Year Later: Actions Taken in the United States and Canada to Reduce Blackout Risk (2004).

# 3. Implementation of the Task Force Recommendations

## Group I: Institutional Issues Related to Reliability
*(Recommendations 1-14)*

**Summary**: In its Group I recommendations, the Task Force addressed a number of institutional issues related to reliability and identified the actions needed by the appropriate governments and regulators in the United States and Canada, including NERC and the Regional Reliability Councils. The actions required include the establishment of mandatory and enforceable standards, strengthening the institutional framework for reliability management (e.g., changes in the structure, function and governance of NERC and the Regional Reliability Councils), and the establishment of a standing framework for the investigation of any future blackout or grid-related disturbances.[5]

Several of the 14 recommendations in Group I have more than one component. As a result, there are a total of 24 Group I components that were tracked. Fourteen of these components have been fully implemented, and as the following details, substantial progress has been made on the remaining ten.

Table 3.1 summarizes the status of the implementation of each of the 24 components and identifies the entities responsible for implementing the recommendation. As noted previously, some of the recommendations involve discrete, one-time actions while others involve policies or actions that are to continue on an ongoing basis. For purposes of reporting on the implementation of the recommendations, the Task Force considered a recommendation, or a component of a recommendation, to be fully implemented when the entity responsible for its implementation accepted the recommendation, developed and implemented the necessary policies or actions and, if appropriate, established plans and procedures for continuing the policies or actions.

[5] Final Blackout Report, p. 141.

**Table 3.1: Summary of Implementation Status of Recommendations 1-14**

| Recommendation Number | Fully Implemented | | Not Yet Fully Implemented | Entity Responsible for Full Implementation |
|---|---|---|---|---|
| | One-Time Action | Ongoing Activity | | |
| R1A | x | | | U.S. Congress |
| R1B | x | | | FERC |
| R1C | | x | | Authorities in Canada |
| R1D | | x | | U.S. and Canadian Governments |
| R1E | | | x | U.S. and Canadian authorities |
| R2 | | x | | FERC, DOE, NERC, U.S. and Canadian authorities |
| R3A | x | | | FERC, DOE, NERC, Canadian authorities |
| R3B | | | x | FERC, DOE, NERC, Canadian authorities |
| R3C | | | x | FERC, DOE, NERC, Canadian authorities, Bilateral Electric Reliability Oversight Group |
| R3D, E, F | | | x | NERC, DOE, FERC, Canadian authorities |
| R4 | | x | | FERC, Canadian authorities |
| R5A | x | | | DOE, FERC, Canadian authorities |
| R5B | | x | | NERC |
| R6 | x | x | | FERC, Canadian authorities |
| R7 | x | | | FERC, Canadian regulatory authorities |
| R8 | x | | | U.S. and Canadian legislative and regulatory authorities |
| R9 | x | | | FERC, Canadian authorities |
| R10 | | | x | EIA, interested agencies and data sources, NRCan, NEB, FPT Working Group |
| R11, 14 | | | x | FERC, EIA, Canadian authorities, NRCan, FPT Working Group |
| R12 | | | x | DOE, NRCan |
| R13 | | x | | DOE |
| **Totals** | **14** | | **10** | |

Note: After the certification of an ERO, the entity responsible for recommendations that will be implemented with the development of a standard will be the ERO.

The following section describes the actions taken to implement each component of the Group I recommendations, and identifies any further actions planned to fully implement the recommendations.

**R1. Appropriate branches of government in the United States and Canada should take action as required to make reliability standards mandatory and enforceable, and to provide appropriate penalties for non-compliance.**

To emphasize the importance of making reliability standards mandatory and enforceable, the Task Force focused its first recommendation on this fundamental goal. The recommendation has five components:

**R1.A The U.S. Congress should enact the reliability provisions proposed in the pending comprehensive energy bill.**

**Actions Taken:** The U.S. Congress passed H.R. 6, the Energy Policy Act of 2005 (EPAct 2005), on July 29, 2005, and the President signed the bill into law on August 8, 2005.[6]

**Action Required to Fully Implement Recommendation 1.A:** No further action is needed to implement the recommendation; although, substantial action is needed to implement the reliability provisions of the legislation.

Full implementation of mandatory reliability standards in the United States requires FERC to issue regulations for the certification of an Electric Reliability Organization (ERO), review applications from parties seeking certification, and certify one ERO.

On February 3, 2006, FERC issued an order pursuant to Subtitle A (Reliability Standards) of EPAct 2005 setting forth requirements for the certification of an ERO.[7] NERC was the only application submitted to FERC seeking certification as the ERO. FERC is currently in the process of reviewing the NERC application. Since NERC also submitted proposed reliability standards as an attachment to its application, those reliability standards are also concurrently under review by FERC. It is anticipated that certification of an ERO will be complete before the end of 2006.

**R1.B** [In the absence of U.S. legislation] **FERC should review its existing authorities to enhance the enforcement of reliability standards, and take action as appropriate.**

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[6] Energy Policy Act of 2005, Pub. L. No. 109-58 (2005).

[7] Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of the Electric Reliability Standards (FERC Order No. 672), 114 FERC ¶ 61,104 (2006).

**Actions Taken:** Prior to the enactment of EPAct 2005, FERC reviewed its existing authorities with respect to electricity reliability standards. FERC issued a Policy Statement on April 19, 2004, stating that its *pro forma* Open-Access Transmission Tariff (OATT) contains numerous references to *good utility practice*, and that FERC interprets this term to include compliance with NERC's reliability standards and the standards of the regional reliability councils.[8] On February 9, 2005, FERC issued a supplement to this Policy Statement affirming that the term "*Good Utility Practice*" required under FERC's OATT includes compliance with the new NERC reliability standards (Version 0) approved by the NERC Board of Trustees on February 8, 2005.[9]

**Action Required to Fully Implement Recommendation 1.B:** No further action is required.

Now that the U.S. reliability legislation has been enacted, NERC has sought certification as the ERO called for in EPAct 2005. For simplicity of presentation, the many forward-looking references to NERC in this document are intended to apply also to the ERO.

**R1.C The Canadian federal and provincial governments should work together, and with U.S. authorities, to develop a framework to ensure that identical or compatible reliability standards apply in both countries.**

**Actions Taken:**

Considerable progress has occurred over the past year with respect to electricity reliability legislation and ERO development and recognition in Canada.

On April 4, 2006, the North American Electric Reliability Council (NERC) filed an Application for Recognition as the ERO with the provinces of Nova Scotia, Ontario and Alberta, and with the National Energy Board. In a companion filing, NERC requested recognition of 102 reliability standards. NERC also filed a Notice of Filing as the ERO with the provinces of New Brunswick, Québec, Manitoba, Saskatchewan and British Columbia. NERC is targeting to have Memorandums of Understanding (MOUs, or their equivalent) in place between NERC and Canadian jurisdictions by December, 2006.

**STATUS BY JURISDICTION**

**Nova Scotia:** Has legislation authority regarding electricity reliability. An order from the Nova Scotia Utility and Review Board (NSUARB) is required regarding ERO recognition. The NSUARB has exchanged draft MOUs with NERC.

[8] Policy Statement on Matters Related to Bulk Power System Reliability, 107 FERC ¶ 61,052, (FERC Policy Statement), clarified 108 FERC ¶61,288 (2004) at P 23.
[9] Supplement to Policy Statement on Matters Related to Bulk Power System Reliability, 110 FERC¶61,096, (FERC Supplement to Policy Statement)(2005) at P 1.

**New Brunswick:** Has legislation authority regarding electricity reliability. NERC standards are currently mandatory and become effective upon approval by NERC.

**Québec:** Legislation authority regarding electricity reliability is in preparation.

**Ontario:** Has legislation authority (Electricity Act, 1998) regarding electricity reliability. NERC standards are currently made mandatory through electricity market rules and become effective upon approval by NERC. The Ontario Energy Board has exchanged draft MOUs with NERC.

**Manitoba:** Legislation is being developed to grant the Public Utilities Board authority over electricity reliability.

**Saskatchewan:** Legislation is needed to regulate utility.

**Alberta:** Has legislation authority regarding electricity reliability. NERC standards are currently mandatory.

**British Columbia:** Both legislation and non-legislative options are under review to confirm the BC Utilities Commission's authority over electricity reliability. A decision is expected this summer on whether an amendment to the Utilities Commission Act may proceed; if so, it may be considered for the Spring 2007 session.

**National Energy Board:** Has legislative authority regarding the construction and operation of international and designated power lines, and electricity exports, under the *National Energy Board Act.* The NEB takes into account reliability when considering authorizations of power line and export applications. The NEB is considering signing an MOU with NERC.

**Action Required to Fully Implement Recommendation 1.C:** As in the United States, implementation of an identical or compatible system of mandatory standards will require the ERO to be established and for it to submit proposed reliability standards to regulatory authorities.

**R1.D An international mechanism should be developed to provide for government oversight of the NERC and the proposed ERO.**

**Actions Taken:** In order to provide coordinated oversight of NERC and the proposed ERO, the U.S. DOE, FERC and the Canadian FPT Working Group, with the assistance of the U.S. State Department and the Department of Foreign Affairs and International Trade established the Bilateral Group. Terms of Reference for the Bilateral Group were signed by the various agencies on June 30, 2005.[10]

The Bilateral Group prepared, *Principles for an Electric Reliability Organization that can Function on an International Basis*, to aid in the establishment of an ERO that can function effectively in the United States and Canada. The principles were prepared through analysis and discussion within the Bilateral Group and through three workshops with the representatives of the reliability councils, regulators, the bulk power industry, and other interested stakeholders. The principles for a reliability organization that can function effectively in the U.S. and Canada, developed by the Bilateral Group, were incorporated into FERC's Notice of Proposed Rulemaking, FERC's Final Rule, and NERC's ERO Application. The Bilateral Group is intended to have an ongoing role in identifying issues related to international aspects of the reliability framework and identifying options for resolution of those issues as well as consult on international aspects of reliability policies and reliability regulatory issues.[11]

**Action Required to Fully Implement Recommendation 1.D:** The mechanism for this ongoing activity has been established.

**R1.E Regulatory authorities in both countries should decide whether to develop a MOU defining their working relationships and reliability responsibilities vis-à-vis NERC.**

**Actions Taken:** FERC directed its staff in its Policy Statement to draft an MOU that would define NERC's working relationship with FERC, clarify the appropriate FERC oversight of NERC, and the respective reliability responsibilities of both FERC and NERC. However, with the enactment the reliability provisions of EPAct, there is no longer a need for an MOU that defines the relationship between FERC and NERC. Rather, the reliability provisions of EPAct define the relationship between FERC and the entity certified as the ERO. The U.S. DOE decided to defer updating its MOU with NERC until after enactment of the reliability legislation. The Canadian Association of Members of Public Utility Tribunals Reliability Subcommittee developed a common template for an MOU between Canadian regulators and NERC, and reviewed it with NERC. Many of the regulators in Canada have indicated that they are considering signing an MOU with NERC. In Alberta, in place of the regulator it will be the Ministry that signs the MOU.

**Action Required to Fully Implement Recommendation 1.E:** FERC, DOE and Canadian authorities need to complete the process of establishing their respective MOUs.

**R2. Develop a regulator-approved mechanism for funding NERC and the Regional Reliability Councils, to ensure their independence from the parties they oversee.**

[10] See the following web site for a press release: http://www.nrcan-rncan.gc.ca/media/newsreleases_e.htm
[11] FERC Order No. 672 at P 127.

**Actions Taken:** The Bilateral Group discussed alternative approaches to funding NERC and the Regional Reliability Councils, and concluded that adoption of a new funding arrangement would be difficult prior to the establishment of an ERO. Accordingly, the Bilateral Group made ERO and Regional Reliability Council funding one of the topics to be discussed at its public workshops involving representatives from the reliability councils, regulatory agencies, the bulk power industry and other interested stakeholders. At the December 2004 workshop, there was broad consensus that the cost of the approved budgets of the reliability councils should be allocated according to *net energy for load* and that the regulatory authority in each jurisdiction should determine a method for collecting its allocated share of the budgets, for example, by a charge on transmission. These points have been incorporated into the Bilateral Group's *Principles for an Electric Reliability Organization that can Function on an International Basis*.

**Action Required to Fully Implement Recommendation 2:** As part of the regulatory process to establish the ERO, FERC Order No. 672 requires the ERO applicant(s) to propose a funding mechanism. FERC and regulators in Canada will then have the opportunity and authority to approve or reject this funding mechanism.

**R3. Strengthen the institutional framework for reliability management in North America.**

This recommendation had the following six components:

**R3.A Commission an independent review by qualified experts in organizational design and management to address issues concerning how best to structure an international reliability organization for the long term.**

**Actions Taken:** Members of the Bilateral Group reviewed studies that were done on this subject in the late 1990s and noted that many of the conclusions of these studies had been incorporated into the framework envisioned for the ERO. Accordingly, the Bilateral Group concluded that any further independent studies should focus on specific subjects or needs, if they arise in the course of the transition to a functional ERO.

**Action Required to Fully Implement Recommendation 3.A:** No further action is required.

**R3.B Based in part on the results of the review—anticipated in R3.A—develop metrics for gauging the adequacy of NERC's performance, and specify the functions of the NERC Board of Trustees and the procedure for selecting the members of the Board.**

**Actions Taken:** FERC intends to use the ERO self-assessments as one of the possible metrics for gauging the adequacy of the ERO's performance for maintaining certification. FERC Order No. 672 mandates a regular performance assessment that requires the ERO to affirmatively demonstrate to FERC that it satisfies the statutory and regulatory criteria for an ERO and is not only maintaining but improving the quality of its activities and those of the Regional Entities to which it has delegated such activities.[12] The ERO is expected to perform an initial assessment three years after certification and every five years thereafter.[13] FERC will review the periodic performance assessment and may require follow-up actions by the ERO to comply or improve compliance with the statutory and regulatory qualifications for the ERO if FERC determines that the ERO has not satisfied specific criteria.[14] Subsequent FERC's review of the ERO's performance assessment and public comments, FERC will issue an order finding that the ERO meets the statutory and regulatory criteria or directing the ERO to comply with or improve compliance with the statutory and regulatory criteria for an ERO. If the ERO fails to comply adequately with the FERC order, the FERC may institute a proceeding to enforce its order including, if necessary and appropriate, a proceeding to consider decertification of the ERO.[15]

Order No. 672 did not mandate a specific approach to ERO governance but allows the ERO candidate(s) to develop and provide a proposal in its application for certification.[16]

In review of NERC's Application for Recognition as the ERO with the provinces of Nova Scotia, Ontario and Alberta, and with the National Energy Board and the remaining jurisdictions when appropriate, questions concerning the ERO Board's functions will be examined further by governmental authorities in Canada. Review of NERC's role and performance in jurisdictions in Canada may also be considered in Memorandums of Understanding (MOUs, or their equivalent) being negotiated between NERC and authorities in Canada.

**Action Required to Fully Implement Recommendation 3.B:** Certification of an ERO and completion of the ERO self-assessment three years after certification. While governmental authorities in Canada do not intend to "certify" the ERO, it will be recognized as a reliability standards setting body. The Bilateral Group will provide for governmental authorities to communicate on the performance of the ERO and to coordinate prior to any action affecting certification of the ERO.

**R3.C Examine and clarify the future role of the Regional Reliability Councils, with particular attention to their mandate, scope, structure, responsibilities, and resource requirements.**

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[12] FERC Order No. 672 at P 186.
[13] FERC Order No. 672 at P 187.
[14] FERC Order No. 672 at P 187.
[15] FERC Order No. 672 at P 187.
[16] FERC Order No. 672 at P 152.

**Actions Taken:** Actions are underway in two areas, described as follows:

***Functions of the Regional Reliability Councils***

In response to the Task Force's recommendation concerning the role of the Regional Reliability Councils, NERC charged its Regional Managers' Committee with examining the future roles and responsibilities of Regional Reliability Councils. The Committee examined a wide range of alternative models for these roles and responsibilities and presented a report to NERC in October 2004.[17] This report recommended incremental changes for Regional Reliability Councils and NERC as well as a transition to the requirements of the then pending U.S. energy legislation. The Committee's report also set out five principles for regional organizations derived from the pending U.S. energy legislation, the functions of Regional Reliability Councils, and the requirements for carrying out these functions. NERC endorsed the Committee's report and requested that the Committee give additional attention to several related matters.

On May 2, 2005, NERC approved a follow-up report from the Committee that included:

- An assessment of ways in which the current Regional Reliability Councils did not conform fully with the principles, functions, and procedural requirements set out in the Committee's October 2004 report;
- Development plans to bring each Regional Reliability Council into full conformance; and
- Development plans for procedural requirements concerning the core functions of developing and enforcing regional reliability criteria and standards.[18]

The roles and functions of regional reliability entities—such as the Regional Reliability Councils—were also discussed extensively in the Bilateral Group's workshops and are addressed to some degree in the Bilateral Group's *Principles for an Electric Reliability Organization that can Function on an International Basis*. These subjects will require further attention as the ERO is formed and regional entities are established in relation to it.

***Simplifying the Reliability Map***

One of the Task Force's concerns about the Regional Reliability Councils was the need for simplification, particularly in some geographic areas of the overlapping boundaries of control areas, and among reliability coordinators, regional transmission organizations or independent system operators, and Regional Reliability Councils.



[17] *Examination of the Future Role of the Regional Reliability Councils and Assessment of Eastern Interconnection Regional Reliability Council Boundaries*, Regional Managers Committee, North American Electric Reliability Council, October 5, 2004

[18] For additional details and documents, including stakeholder comments related to the *Role of the Regions Study*, see NERC's web site http://www.nerc.com/~filez/roleofregions.html.

In parallel with the Regional Managers' Committee's assessment of Regional Reliability Council roles, members of the East Central Area Reliability Coordination Agreement (ECAR), the Mid-Atlantic Area Council (MAAC), the Mid-America Interconnected Network (MAIN), and the Mid-West Reliability Organization (MRO) initiated discussions with the objective of forming a single Regional Reliability Council, referred to as the Large Regional Reliability Council (LRRC). The Boards of the four Regional Reliability Councils have committed resources to forming a single Regional Reliability Council under the NERC structure and creating a uniform set of reliability standards for the combined regions.[19] MRO is participating as an observer at this stage but is likely to join the LRRC at a later date. NERC approved ReliabilityFirst as one of eight Regional Reliability Councils, effective January 1, 2006. ReliabilityFirst is the successor organization to three NERC Regional Reliability Councils: MAAC, ECAR and MAIN.

The Task Force welcomes the work of the Regional Managers' Committee and the Regional Reliability Councils, as well as the work of the four councils previously noted. These developments should streamline the Regional Reliability Councils, enhance reliability assurance, and assist in the transition to mandatory reliability standards.

**Action Required to Fully Implement Recommendation 3.C:** When an ERO is certified, the roles of Regional Reliability Councils with delegated authority to function as Regional Entities under EPAct 2005 will be an important aspect of the transition from voluntary operating and planning standards to mandatory and enforceable Reliability Standards.

**R3.D Examine NERC's proposed Functional Model and set minimum requirements under which NERC would certify applicants' qualifications to perform critical functions.**

**R3.E Request NERC and the Regional Reliability Councils to suspend certification of any new control areas—or sub-control areas—until the minimum requirements in Section D have been established, unless an applicant shows that such designation would significantly enhance reliability.**

**R3.F Determine ways to enhance reliability operations in the United States through simplified organizational boundaries and resolution of seams issues.**

**Actions Taken:** Components D, E, and F of Recommendation 3 are aimed at simplifying the number of entities performing reliability functions in the United States. For example, the Midwest Independent Transmission System Operator (MISO), as the reliability coordinator for its region, is responsible for dealing with 37 control areas

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[19] Further information regarding the LRRC initiative may be found at http://www.maac-rc.org/rrcboundaries/work-teams.html.

compared with one or two control areas in several other regions in the Eastern Interconnection.[20]

Prior to the restructuring of the electric power industry in the 1990s, each integrated utility was responsible for performing all of the reliability functions within its service area. Restructuring changed the roles of the utilities and introduced new players and demands on the bulk power system. As a result, NERC developed the Functional Model, which defines each of the functions required to ensure reliability and meet the needs of the marketplace. Entities register with NERC to declare which reliability functions they perform; in turn, by registering for particular functions, the entities become responsible for complying with the NERC standards specifically applicable to those functions. The Functional Model went into effect on April 1, 2005, with the new Version 0 NERC reliability standards. Work continues on refining the model and, as they have for many years, the standards will continue to evolve over time. Thus, the Functional Model provides a framework through which NERC and the industry can develop, maintain and implement reliability standards.[21]

Members of the Bilateral Group discussed with NERC whether registration of new control areas could be suspended, as well as other measures, such as setting minimum requirements for registration taken to reduce fragmentation in some regions of the United States. In NERC's view, the Functional Model is purposely designed to be independent of industry structures—in fact, it is intended to accommodate the many entity structures that currently exist and may form in the future. NERC's certification requirements for the entities registered as Reliability Authorities, Balancing Authorities and Transmission Operators, as defined in the Functional Model, are intended to ensure that these entities are capable of performing the functions for which they register.

Concerns regarding organizational complexities, particularly for the Midwestern United States, have moderated to some degree as a result of ongoing developments in bulk power markets. The commercial advantage of generators functioning as control areas appears to have declined, as generators are not registering as balancing authorities in significant numbers. Expansion of the Pennsylvania-New Jersey-Maryland Interconnection (PJM) Regional Transmission Organization across the Midwest consolidated a number of balancing authorities into the single PJM system that performs this balancing function. In addition, MISO has made major changes and improvements, partly in response to the NERC actions and Task Force recommendations that stemmed from the investigation of the August 14, 2003 blackout.

In 2004, MISO invested in several key areas of concern, including:

- Reliability tools and monitoring capabilities;
- Training for MISO and control area staff;



[20] As part of NERC's implementation of the Functional Model, control areas are now known as *balancing authorities*. In this report *control areas*, *control area operators*, and *balancing authorities* should be considered equivalent terms.
[21] *NERC Reliability Functional Model*, Functional Model Working Group, April 19, 2005, pp. 6-8.

- Communications systems and protocols between MISO and its control areas and the adjoining Reliability Coordinators;
- Command authority between MISO, its control areas, and adjacent reliability councils; and
- Communications, coordination and information sharing through seams arrangements with PJM.[22]

In addition, NERC is investigating the merits of transforming the wide-area inter-regional studies it currently performs into interconnection-wide analyses that would transcend the organizational boundaries in the Eastern Interconnection.

In summary, NERC's Functional Model was not intended to address the issue of institutional fragmentation that may have been a factor in the cascading of the August 14, 2003 power outage. However, the model will provide greater clarity as to who is responsible for which tasks in order to guarantee reliability. Also, there has been important progress in addressing the Task Force's underlying concerns. These concerns have been addressed through a number of approaches, including NERC's Reliability Readiness Assessment Program, which examines whether operators of the bulk power electric system have the facilities, tools, processes, and procedures in place to operate reliably under future conditions; the work to replace four Regional Reliability Councils with a single Large Regional Reliability Council; the apparent decline in commercial advantage of generators operating as control areas; expansion of the PJM system; and numerous functional improvements at MISO.

**Action Required to Fully Implement Recommendations 3.D, 3.E, and 3.F:** The Task Force urges NERC to continue seeking opportunities that will improve coordination across organization boundaries, and to continue developing interconnection-wide reliability studies.

Recommendations 3.D, E and F will be fully implemented with the certification of an ERO that will provide the framework for reliability management in North America.

**R4. Clarify that prudent expenditures and investments for bulk system reliability (including investments in new technologies) will be recoverable through transmission rates.**

**Actions Taken:** In the United States, on April 19, 2004, FERC issued a policy statement on reliability issues that, among other things, affirmed the continuation of its policy of approving applications to recover the prudently incurred costs necessary to ensure bulk electric system reliability.[23]

[22] Midwest Independent Transmission System Operator, 2004 Annual Report.
[23] FERC Policy Statement at P 28.

The U.S. DOE and FERC are both strengthening their capacities to work closely with the states on matters related to transmission adequacy and reliability, paying particular attention to transmission planning, cost allocation for multi-state transmission projects, and ensuring the timely recovery of prudent expenditures by transmission investors. Much of this work is done jointly with regional, state-based organizations such as the Western Governors Association and the Organization of MISO States and with national organizations such as the National Association of Regulatory Utility Commissioners and the National Council of State Legislatures.

In Canada, provincial authorities, which are responsible for the regulation of the bulk power system within the province, have advised the Task Force that they support the recovery of prudently incurred costs for bulk system reliability and have procedures in place for this purpose.

**Action Required to Fully Implement Recommendation 4:** The specific action required under Recommendation 4 has been completed. In the United States, however, regionally-focused collaborative efforts involving federal, state and industry officials on cost allocation and cost recovery for new transmission investments will be required for at least the next several years. Further, for the U.S. regions bordering Canada, coordination with regulators and the electricity industry in Canada will also be required.

**R5. Track implementation of recommended actions to improve reliability.**
This recommendation had two components:

**R5.A Relevant agencies in the United States and Canada should cooperate to establish mechanisms for tracking and reporting to the public on implementation actions in their respective areas of responsibility.**

**Actions Taken:** On August 13, 2004, the American and Canadian co-leads of the Task Force issued a report on the progress of the implementation of the Task Force's recommendations.[24] The present report provides an updated assessment of implementation efforts.

**Action Required to Fully Implement Recommendation 5.A:** The specific action required by Recommendation 5.A has been completed. Looking ahead, periodic joint reports are likely to be issued on actions taken, and actions needed, to maintain the reliability of the North American bulk electric system.

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[24] Report to the U.S. and Canada Power System Outage Task Force, The August 14, 2003, Blackout One Year Later: Actions Taken in the United States and Canada to Reduce Blackout Risk (2004). This report is available from the web sites of the U.S. DOE at: http://www.electricity.doe.gov/documents/blackout_oneyearlater.pdf and from Natural Resources Canada (NRCan) at: http://www.nrcan-rncan.gc.ca/inter/poweroutage2003_e.html.

**R5.B NERC should draw on the quarterly reports [received] from its Regional Reliability Councils to prepare annual reports to FERC, appropriate authorities in Canada, and the public on the status of the industry's compliance with recommendations and important trends in electric system reliability performance.**

**Actions Taken:** NERC and the Regional Reliability Councils are tracking the implementation of the Task Force's Group II recommendations that apply specifically to NERC, the Regional Reliability Councils, and the bulk power industry. NERC and the Regional Reliability Councils also cooperated with the departments and agencies in the United States and Canada to support the work of the Task Force. On August 11, 2004, NERC released an interim report on the implementation of its recommendations and those of the Task Force entitled, *Status Report on NERC Implementation of August 2003 Blackout Recommendations*.[25]

The report noted the following significant achievements:

- Correction of the direct causes of the blackout;
- Performance of independent, on-site readiness assessments of all major system operators; and
- Clarification of existing reliability standards and development of new standards to ensure that the reliability *rules of the road* are understood, and followed, by all entities whose operations affect reliability.

In July 2005, NERC approved a second report on the implementation of the recommendations by NERC, the Regional Reliability Councils, and the bulk power industry entitled, *Implementing the August 14, 2003 Blackout Recommendations, Status Report*. This report provides a description of the progress on each of the recommendations. NERC continued to provide updates to its board of trustees on the status of the implementation of the blackout recommendations, with reports at the August and November 2005 and February 2006 meetings of its board. Going forward, the status of activities initiated as a result of the blackout investigation will be reported as part of the NERC/ERO program reports at each of its board meetings. All board agendas are posted on the NERC web site.

**Action Required to Fully Implement Recommendation 5.B:** The specific action required under Recommendation 5.B has been completed. In the future, periodic reports from NERC or the ERO on the status of actions and developments related to reliability will be needed to inform regulatory authorities and the public.

**R6. FERC should not approve the operation of a new Regional Transmission Operator (RTO) or Independent System Operator (ISO) until the applicant has met the minimum functional requirements for reliability coordinators.**

[25] Status Report on NERC Implementation of August 2003 Blackout Recommendations, North American Electric Reliability Council, August 11, 2004. See NERC's web site www.nerc.com.

**Actions Taken:** In its policy statement on reliability matters dated April 19, 2004, FERC mandated that an ISO or RTO must meet all minimum functional requirements for reliability coordinators in order to fulfill its responsibility as reliability coordinator for the area within its footprint.[26]

**Action Required to Fully Implement Recommendation 6**: The specific action required by Recommendation 6 has been completed. FERC confirmed that it will continue its policy of considering the reliability implications before authorizing a new RTO or ISO.

**R7. Require any entity operating as part of the bulk power system to be a member of a Regional Reliability Council if it operates within the council's footprint.**

**Actions Taken:** The stated objective of this recommendation was to ensure that all relevant parties are subject to NERC standards, policies, etc., in all NERC regions in which they operate.[27] The Task Force proposed membership in the Regional Reliability Councils as a vehicle towards achieving this objective. However, as planning for the implementation of mandatory standards has developed there is a direct requirement of all participants in bulk power operations to comply with reliability standards, independent of whether the party is a member of a reliability organization.

In the United States, EPAct 2005, Title XII-Electricity requires compliance with the relevant reliability standards by all parties whose actions affect the bulk power system, but it does not require membership in the ERO or a Regional Reliability Council. Similarly, in Canada, the implementation of mandatory reliability standards by provincial and territorial authorities will not depend upon membership in a reliability organization.

Prior to the full implementation of mandatory standards across the United States and Canada, regulatory authorities in both countries have taken action to enhance compliance with reliability standards. As noted previously, in its April 19, 2004 policy statement on reliability matters, FERC affirmed that in view of its interpretation that "*Good Utility Practice*" included compliance with NERC reliability standards and NERC compliance audit recommendations.[28] In many Canadian provinces there is already legislation and regulations or contractual arrangements in place requiring compliance with reliability standards.

**Action Required to Fully Implement Recommendation 7:** No further action is required under this recommendation.

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[26] FERC Policy Statement at P 36.
[27] Final Blackout Report, p. 147.
[28] FERC Supplement to Policy Statement at P 1.

**R8. Shield operators who initiate load shedding pursuant to approved guidelines from liability or retaliation.**

**Actions Taken:** In the United States, some state regulators have informally expressed the view that there is appropriate protection against liability suits for parties who shed load according to approved guidelines. In addition, FERC's Policy Statement of April 19, 2004, stated that the Commission will consider, on a case-by-case basis, proposals by public utilities to amend their Open Access Transmission Tariffs to include limitations on liability.[29]

In Canada, provincial and territorial authorities report that current statutes, regulations, and tariffs provide appropriate protection against liability suits for parties who shed load according to approved guidelines.

NERC has taken relevant action on two fronts. First, NERC recently adopted the Version 0 NERC reliability standards to provide direction to operators on when they should *manually* initiate load shedding. Operators who shed load pursuant to the approved guidelines are presumed to have adequate protection against liability claims. Second, as discussed below, the Regional Reliability Councils are reviewing the applicability of *automatic* load-shedding plans in specific geographic areas, and are to present the conclusions of this review, with recommendations, to NERC.

**Action Required to Fully Implement Recommendation 8:** No further action under this recommendation is needed.

**R9. Integrate a "reliability impact" consideration into the regulatory decision-making process.**

**Actions Taken:** In the United States, FERC stated in its April 19, 2004, policy statement that reliability concerns would be factored into its regulatory decisions.[30] To ensure this result, FERC established the Division of Reliability to assure integration of reliability and market consideration in the Commission's decision making.

In Canada, most provincial regulators explicitly take reliability impacts into account in their decision-making. However, in a few provinces with provincially-owned electric utilities, responsibility for reliability is assigned to the utility. The National Energy Board, which is responsible for the authorization of the construction and operation of international power lines and electricity exports, includes an assessment of the reliability impacts of its regulatory process.

**Action Required to Fully Implement Recommendation 9:** No further action is required under this recommendation.

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[29] FERC Policy Statement at P 40.
[30] FERC Policy Statement at P 37.

**R10. Establish an independent source of reliability performance information.**

**Actions Taken:** In the United States, two recent government-sponsored reports have stressed the need for a more systematic collection, analysis and publication of reliability data and information.[31] FERC, DOE, the Energy Information Administration, and NERC need to agree on what data should be collected by whom, and what analyses of reliability data should be published routinely by which organization.

In Canada, the National Energy Board has agreed to prepare a report documenting the reliability information now being collected, the methodologies used, and any gaps or difficulties in the collection of information.

**Action Required to Fully Implement Recommendation 10**: Full implementation of this recommendation will require sustained attention from government agencies over the next several years.

**R11. Establish requirements for collection and reporting of data needed for post-blackout analyses.**

**Actions Taken:** Implementation of this recommendation is closely linked with the implementation of Recommendation 14. See Recommendation 14 for a discussion of the status of efforts to implement both recommendations.

**R12. Commission an independent study of the relationships among restructuring, competition, and reliability.**

**Actions Taken:** The Task Force Final Blackout Report on the August 14, 2003 blackout identified the specific causes of the outage. The restructuring of the bulk power industry was not identified as one of the causes.[32] Nevertheless, some participants in public meetings argued that restructuring was a contributing factor. As restructuring is a complex and often contentious topic, the Task Force recommended further examination of the subject.

The DOE and NRCan concluded that the best way to explore this complex area was to invite discussion papers on the topic from key industry leaders and experts. The papers are posted on the Departments' web sites for public review. In addition, NRCan and DOE hosted two public workshops focused on the discussion papers, one in Washington, D.C, on September 15, 2005, and one in Toronto, Ontario, on September 28, 2005. The authors reflected a broad range of perspectives from the United States and Canada, including those of owners, operators and users of the bulk power system, power consumers, government, regulatory authorities, academic experts, and other interested industry organizations and individuals.

[31] Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis. U.S.DOE/EIA–0639. December, 2004; LBL report (forthcoming).
[32] Final Blackout Report, pp. 17-22.

The authors addressed what they regarded as the important relationships between the ongoing restructuring of the electricity sector in the United States and Canada, competition and reliability. The goal of the discussion papers was to frame relevant aspects of the potential impacts of competition on reliability and then to assess these impacts critically. In addition, the authors offered their perspectives on the appropriate next steps to address the impacts they identified.

A draft final paper has been prepared that reports on the experts' discussion papers as well as public comments received either at the workshops or through written submissions to the DOE or NRCan.

**Action Required to Fully Implement Recommendation 12:** The recommendation will be fully implemented with the release of the final report. DOE and NRCan are expected to release the report shortly.

**R13. DOE should expand its research programs on reliability-related tools and technologies.**

**Actions Taken:** Through the Office of Electricity Delivery and Energy Reliability, the DOE conducts an active and diversified reliability-related R&D program. The Administration has strongly supported this program in the budgets it submits to the U.S. Congress, and will continue to do so. Congress determines the funds available for this work through its annual appropriations process.

**Action Required to Fully Implement Recommendation 13**: No specific additional action is required. DOE will continue to implement this recommendation on an ongoing basis.

**R14. Establish a standing framework for the conduct of future blackout and disturbance investigations.**

**Actions Taken** (Recommendations 11 and 14): As an aid to implementing Recommendations 11 and 14, DOE engaged Alison Silverstein as a consultant to review the August 14 blackout investigation. The purpose of this review was to identify required data that needed to be gathered for any future post-blackout investigations and any actions industry and government agencies should take in preparation for initiating such investigations efficiently and with very short notice. Ms. Silverstein was one of the co-leads for the investigation of the August 14 blackout. Her report, *Preparing for the Next Blackout Investigation*,[33] is based on interviews with more than twenty of the key participants in that investigation.

[33] Preparing for the Next Blackout Investigation, Alison Silverstein, in press.

In February 2005, Ms. Silverstein reported her draft findings to NERC's Board and Stakeholders Committee. Her report led to a decision by the Board to support a plan whereby specific types of time-synchronized grid-related data will be collected routinely and retained for some minimum period so that they will be available, if needed, for an investigation by a NERC/industry group or another group acting in combination with government agencies. Conceptually, the intent was to devise a functional analogue of the automatic *black box* data recordings now required on commercial aircraft which help investigators, in the event of a crash, determine its cause.

In May 2005 the NERC Board of Trustees approved, *Blackout Disturbance and Response Procedures*, a basic framework for investigations by NERC and the industry. In addition, NERC has initiated a process to develop a standard that will establish requirements for time-synchronized disturbance monitoring equipment (DME).

Two new standards – Define Regional Disturbance Monitoring and Reporting Requirements, and Disturbance Monitoring Equipment Installation and Data Reporting – were posted for a 30-day pre-ballot review through June 14, 2006. Also, a proposed new standard, to be drafted in 2006 and approved in 2007, will set requirements for the real-time monitoring and recording of system performance using phasor measurement devices. The August 2003 blackout proved the value of such devices in analyzing the causes and failure modes of major system disturbances. [See recommendations 28.B and C.]

**Action Required to Fully Implement Recommendation 11:** Once the DME standard is fully implemented and integrated into the *Blackout Disturbance and Response Procedures*, the requirements of Recommendation 11 will have been met. The procedures will, however, require periodic updating as technologies and practices evolve. In the interim, for guidance, NERC and its members will rely on their experience from the August 2003 blackout, the Silverstein Report, and the May 2005 report on DME requirements by the NERC Interconnection Dynamics Working Group.

**Actions Required to Fully Implement Recommendation 14:** A basic premise of both NERC's actions to date in implementing Recommendation 11 and that of the Silverstein Report is that although any significant grid-related disturbance or blackout will merit investigation, only a very small percentage of such incidents will warrant government involvement in the investigation. That is, in most cases NERC will investigate the matter under its *Blackout Disturbance and Response Procedures* and notify government agencies of its findings.

In some situations, however, the circumstances may be sufficient to cause the U.S. President, the Canadian Prime Minister, or both, to decide that government participation in the investigation is appropriate. The Silverstein Report addresses this contingency and recommends a number of actions that U.S. and Canadian agencies should consider, some of which would require U.S. – Canada coordination, and others that would require coordination with NERC. One of the findings of the Silverstein Report is that if an event of sufficient magnitude to warrant government involvement occurs, a number of important actions by government parties are likely to be needed within the first few days. The report identifies such actions and provides reasons why the governments should consider taking them.

DOE, FERC, and the appropriate authorities in Canada are reviewing the Silverstein Report and determining the steps that need to be taken by government agencies individually and jointly towards achieving the objectives of Recommendation 14.

## Group II: Support and Strengthen NERC Actions of February 10, 2004 *(Recommendations 15 through 31)*

**Summary:** Based on the findings of the joint government-industry investigation of the August 14, 2003 blackout, NERC and its Board determined that many actions were needed to adequately prepare the industry for the summer of 2004 and beyond. As a result, the NERC Board of Trustees issued a number of directives on February 10, 2004 - *Actions to Prevent Future Cascading Blackouts*. At that time, FirstEnergy Corp. (FirstEnergy), MISO, and PJM were directed to complete a series of remedial actions by June 30, 2004 which would correct deficiencies identified as factors contributing directly to the blackout. Also at that time, the Regional Reliability Councils and other NERC committees and task forces were directed to complete a number of assignments by various dates. In its final report, the Task Force strongly supported these directives, and recommended certain additional requirements in its Recommendations 15 through 31.

As was the case with Group I, some of the actions the Task Force called for in this group of recommendations were one-time-only measures, and others involved the development of requirements or capabilities and the exercise of them on an on-going basis. As illustrated in Table X-X, implementation of some of these recommendations is completed, while others require additional effort. [Summary Table to be completed after final draft.]

The following discussion outlines the actions taken to implement each component of the Group II recommendations, and identifies further actions, if needed, to implement them fully.

It should be noted that NERC has contributed to, and agreed with, the accuracy and completeness of the ***Actions Taken*** and the ***Actions Required*** under each of the recommendations that are within NERC's control and responsibility. Many of the ***Actions Taken*** sections were obtained from NERC's web site, NERC documents, or input provided by NERC staff.

It is important to recognize that with the passage of the EPAct 2005, and the certification of an ERO, all reliability standards will undergo a formal review and approval process by FERC and affected Canadian provincial regulators. The standards may be remanded to the ERO if regulatory agencies find that they do not meet applicable requirements.

Many of the Task Force's Group II recommendations are being implemented through the development and implementation of mandatory reliability standards. These standards are subject to a process of review, remand and approval by FERC and regulatory authorities in Canada. The FERC staff preliminary assessment of the NERC's proposed mandatory reliability standards identifies some proposed standards that may not fully implement the Task Force's recommendations. However, the Task Force is confident that the review and approval processes for the mandatory reliability standards will identify and resolve deficiencies in the standards proposed by NERC or the ERO.

The Task Force thanks NERC, its Board of Trustees and the Regional Reliability Councils for their efforts in implementing the Task Force recommendations.

**TABLE 3.2: Summary of Implementation Status of Recommendations 15 to 31**

| Recommendation Number | Fully Implemented | | Not Yet Fully Implemented | Responsible Entity |
|---|---|---|---|---|
| | One-Time Action | Ongoing Activity | | |
| R15.A.1-11 | x | | | NERC, FirstEnergy |
| R15.B.1 | x | | | NERC, MISO |
| R15.B.2 | x | | | NERC, MISO |
| R15.C | x | | | NERC, PJM |
| R15.D.1 | ? | | | NERC, ECAR |
| R15.D.2 | ? | | | NERC, ECAR |
| R15.D.3 | ? | | | NERC, ECAR |
| R15.E.1 | ? | | | NERC, Other parties |
| R15.E.2 | ? | | | NERC, Other parties |
| R16.A | | | x | NERC, Industry |
| R16.B | | x | | NERC, Transmission Operators |
| R16.C | | | x | NERC, Regional Reliability Councils |
| R16.D | | x | | U.S. and Canadian authorities, Transmission Owners |
| R17.A | | | x | NERC, Regional Reliability Councils |
| R17.B | | x | | NERC |
| R17.C | ? | | | NERC |
| R17.D | | x | | NERC |
| R17.E | | x | | NERC |
| R17.F | | | x | NERC |
| R18.A | | x | | NERC |
| R18.B | | | x | NERC |
| R19.A - C | | | x | NERC |
| R20 | | | x | NERC |
| R21.A | x | | | NERC |
| R21.B | | | x | NERC |
| R21.C | x | | | NERC |
| R22.A | | | x | NERC |
| R22.B.1 | | | x | NERC |
| R22.B.2 | | ? | | NERC |
| R23 (1) | | | x | NERC, Industry |
| R23 (2) | | ? | | NERC |
| R24 | | | x | FERC, Canadian authorities |
| R25.A - D | x | | | NERC |
| R26 | x | | | NERC |

| Recommendation Number | Fully Implemented | | Not Yet Fully Implemented | Responsible Entity |
|---|---|---|---|---|
| | One-Time Action | Ongoing Activity | | |
| R27 | | | x | NERC |
| R28.A | x | | | FERC, Canadian authorities |
| R28.B | | | x | NERC, Regional Reliability Councils, Control Areas, Transmission Owners |
| R28.C | | | x | NERC |
| R28.D | | x | | FERC, Canadian authorities |
| R29 | x | | | NERC |
| R30 | | | ? | NERC |
| R31 | | | x | NERC |
| **Group II Totals** | **23[plus 6?]** | **8[plus 2?]** | **18[plus1?]** | |

Note: After the certification of an ERO, the entity responsible for recommendations that will be implemented with the development of a standard will be the ERO.

**R15. Correct the direct causes of the August 14, 2003 blackout.**

This recommendation includes five components, some of which have several sub-components.

**R15.A: Corrective actions to be completed by FirstEnergy by June 30, 2004.**

**R15.A.1.** In addition to measures to improve reliability in the Akron-Cleveland area and to avoid risks to neighbouring systems, **NERC should require FirstEnergy to review its entire service territory, in all states, to determine whether any vulnerabilities exist—similar to those that contributed to the onset of the blackout in northern Ohio—and require prompt attention. This review should be completed by June 30, 2004. The results should then be reported to FERC, NERC, and appropriate regulatory authorities.**

**Actions Taken:** FirstEnergy took the view that PJM is responsible for the assessment of transmission security in the PJM footprint, which includes the areas of FirstEnergy's service territory outside northern Ohio. PJM conducted evaluations for the summer of 2004 and had presented the results to the appropriate state commissions. FirstEnergy sent its summer 2004 assessment for its Ohio territory to ECAR, and ECAR forwarded it to NERC, FERC, and the Public Utility Commission of Ohio.[34]

**Action Required to Fully Implement Recommendation 15.A.1:** No further action needed.

[34] See http://www.nerc.com/~filez/remedialactionresponses.html, NERC Recommendation Verification Team, FirstEnergy Report, p.26.

**R15.A.2.** In addition to determining minimum acceptable voltage levels within the FirstEnergy Control Area and minimum dynamic reactive reserve levels, NERC should appoint a team, joined by representatives from FERC and the Ohio Public Utility Commission, to review and approve interim voltage criteria to be developed by FirstEnergy.

**Actions Taken:** FirstEnergy developed the criteria as required, and they were approved by the review team. The interim voltage criteria have been replaced by permanent criteria.[35]

**Action Required to Fully Implement Recommendation 15.A.2:** No further action needed.

**R15.A.3. If a FERC-ordered study[36] found that system reinforcements were needed in FirstEnergy's system in order to meet voltage criteria, FirstEnergy was to develop a plan for providing such reinforcements. A team appointed by NERC and joined by representatives from FERC and the Ohio Public Utility Commission should review and approve this plan.**

**Actions Taken:** The reliability study was completed and submitted to FERC on April 22, 2004.[37] FirstEnergy affirmed that the results of the study were being incorporated into the company's planning and operations. The reliability study did not identify any needed system upgrades for summer 2004. Therefore, no reinforcement plan was developed.[38]

**Action Required to Fully Implement Recommendation 15.A.3:** No further action needed.

**R.15.A.4. In addition to NERC's requirement for inspection and testing of all reactive resources, FirstEnergy should be required to confirm that all non-utility generators in its area have entered into contracts for the sale of generation committing them to producing increased or maximum reactive power when called upon by FirstEnergy or MISO to do so.**

**Actions Taken:** Testing was done to the extent prudent. Some large generating units in FirstEnergy's footprint could not be tested to their maximum VAR limits due to system limitations, i.e., the test itself could exceed the system's voltage limits**.** In addition,

[35] Ibid., p.5.
[36] Study of the Capability of the Power System in Northeastern Ohio, 105 FERC ¶ 61,372 (2004).
[37] FirstEnergy Transmission Reliability Study, Docket No. PA04-14. April 22, 2004.
[38] Ibid., p. 26.

FirstEnergy confirmed that, if necessary, it could order non-utility generators in its service area to increase reactive power output to the maximum.[39]

**Action Required to Fully Implement Recommendation 15.A.4:** No further immediate action needed. However, when system conditions permit it in the future, the tests should be carried out as indicated by FirstEnergy.

**R15.A.5. In addition to requiring that FirstEnergy prepare and submit to ECAR an Operational Preparedness and Action Plan, NERC should require FirstEnergy to provide copies of its *Operational Preparedness and Action Plan* to FERC, DOE, the Ohio Public Utilities Commission, and the public utility commissions in other states in which FirstEnergy operates. NERC should also require FirstEnergy to invite its system operations partners—its neighbors to participate in the development of the plan and agree to aspects that could affect their respective systems and operations.**

**Actions Taken:** FirstEnergy stated that its summer 2004 assessment was distributed to FERC, DOE, and the New Jersey Board of Public Utilities, the Pennsylvania Public Utility Commission, and the Public Utility Commission of Ohio. FirstEnergy's system operations partners have participated in ECAR's transmission system studies.[40] NERC's Resource Issues Subcommittee (RIS) and Transmission Issues Subcommittee (TIS) have reviewed FirstEnergy's studies and determined them to be adequate.

**Action Required to Fully Implement Recommendation 15.A.5:** No further action needed.

**R15.A.6. In addition to requiring FirstEnergy to develop a capability to reduce load in the Cleveland-Akron area (1500 MW within ten minutes of a directive by MISO or the FirstEnergy system operator), NERC should require MISO's approval of any change by FirstEnergy from the load reduction capability called for by NERC on February 10, 2004). Further, NERC should require FirstEnergy to share its load reduction plan with the Ohio Public Utility Commission, and FirstEnergy was to communicate with all communities in the affected areas about the plan and its potential consequences.**

**Actions Taken:** FirstEnergy filed its load reduction plan with the Ohio Public Utility Commission. FirstEnergy also participated in a FERC technical conference in Cleveland on July 15, 2004, where it detailed all of the actions taken to address the direct causes of the blackout, including its load reduction plan. This was a public conference that was widely attended by government agencies and consumers.[41]

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[39] Ibid., pp. 8, 27.
[40] Ibid., p. 27.
[41] See: ftp://www.nerc.com/pub/sys/all_updl/docs/bot/Agenda-Items-1005/Item8.pdf, NERC's November 1, 2005, report to the Board of Trustees, p. 3.

**Action Required to Fully Implement Recommendation 15.A.6:** No further action needed.

**R15.A.7. In addition to requiring FirstEnergy to develop an emergency response plan, NERC should require FirstEnergy to offer its system operations partners—its neighbours—an opportunity to contribute to the development of FirstEnergy's Emergency Response Plan and indicate their agreement with its key provisions.**

**Actions Taken:** See R15.A.5.

**Action Required to Fully Implement Recommendation 15.A.7:** No further action needed.

**R15.A.8. In addition to requiring FirstEnergy to develop communications procedures within its organization and with MISO and others, NERC should require FirstEnergy to share its communications procedures with adjacent control areas, plus MISO, PJM, and ECAR, and any other affected system operations partners, and that these procedures be tested in a joint drill.**

**Actions Taken:** NERC verified that FirstEnergy participated in a joint drill with MISO and ECAR in June 2004. Also, a FirstEnergy-MISO-PJM MOU, established under the *PJM-MISO Joint Operating Agreement*, covers the on-going coordination of operations and planning. The parties meet quarterly under this MOU to discuss communications procedures and protocols.[42]

**Action Required to Fully Implement Recommendation 15.A.8:** No further action needed.

**R15.A.9. In addition to requiring FirstEnergy to ensure that its state estimator and real-time contingency analysis functions are used properly, NERC should require FirstEnergy to ensure that its information technology (IT) support team does not change the effectiveness of reliability monitoring or management tools in any way without the awareness and consent of its system operations staff.**

**Actions Taken:** FirstEnergy developed comprehensive, documented procedures for changing management control and communications with system operators. These procedures cover both planned and unplanned outages.[43]

**Action Required to Fully Implement Recommendation 15.A.9:** No further action is needed.

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[42] Ibid., p. 3.

[43] See http://www.nerc.com/~filez/remedialactionresponses.html, NERC Recommendation Verification Team, FirstEnergy Report, p. 18.

**R15.A.10. In addition to requiring FirstEnergy to implement all known fixes to its GE XA21 energy management system (EMS) prior to installing its new EMS, NERC should require FirstEnergy to design and test the transition to its planned new energy management system to ensure that the system functions effectively, that the transition is made smoothly, that the system's operators are adequately trained, and that all operating partners are aware of the transition.**

**Actions Taken:** In the fall of 2003, FirstEnergy implemented the General Electric developed patch to the XA21 system. FirstEnergy successfully converted to a new energy management system acquired from software developer Areva SA on May 1, 2004.[44] (See Recommendation 15.E.2.)

**Action Required to Fully Implement Recommendation 15.A.10:** No further action needed.

**R15.A.11. In addition to requiring that all reliability coordinators, control areas, and transmission operators provide at least five (5) days of training and drills using realistic simulations of system emergencies for each staff person with responsibility for real-time operation or reliability monitoring of the bulk power system, the Task Force recommended that to provide effective emergency preparedness training for FirstEnergy operators before June 30, 2004, NERC should require FirstEnergy to consider seeking the assistance of another control area operator or reliability coordinator known to have a quality training program to provide the needed training with appropriate FirstEnergy-specific modifications**.

**Actions Taken***:* NERC established the FirstEnergy Verification Team (FEVT) to independently verify that FirstEnergy had implemented the policies, procedures, and actions contained in the recommendations of the February 26–27, 2004 *FirstEnergy Readiness Audit* report, including recommendations on emergency preparedness training for FirstEnergy operators. As a result of these recommendations, FirstEnergy met with a number of neighboring utilities—Northern Indian Public Service Company, Ameren Corporation, American Electric Power Company, Inc., Dominion Resources, Inc., etc.—and made several improvements to its operator training program. The FEVT, which met again with FirstEnergy, June 22–23, 2005, included the following statement in its report[45] regarding operator training:

***"FirstEnergy has integrated and is using a Dispatcher Training System (DTS) as part of its operator training program. FirstEnergy demonstrated the use of the DTS in a training exercise. The FEVT was impressed by the depth and completeness of the***

[44] Ibid., p. 28.
[45] ftp://www.nerc.com/pub/sys/all_updl/rap/audits/FEVT_Final_Report.pdf

***developed scenarios, the interest and involvement of the trainees, and the positive and challenging environment maintained by the trainer."***

The FEVT is also preparing an *Example of Excellence* related to FirstEnergy's training program based on its June 22–23, 2005 audit.

**Action Required to Fully Implement Recommendation 15.A.11:** No further action needed. However, training of control room operators and their support staff must be an ongoing exercise in order to keep abreast of new methods and technologies. It will also be necessary for FirstEnergy, other Regional Transmission Organizations and Reliability Coordinators to demonstrate full compliance with NERC Training Standards once the standard has been approved. (See Recommendation 19.)

**R15.B. Corrective actions to be completed by MISO by June 30, 2004.**

**R15.B.1. In addition to its requirements for numerous upgrades of MISO's operating tools and procedures, NERC should require MISO to ensure that its IT support team does not change the effectiveness of reliability monitoring or management tools in any way, without the awareness and consent of its system operations staff.**

**Actions Taken:** Many improvements to MISO's operating and visualization tools, operator training, and communications protocols and procedures were documented by NERC.[46] NERC specifically verified that MISO "has developed procedures to ensure that its' IT support team does not change the effectiveness of reliability monitoring or management tools in any way without the awareness and consent of its systems operations staff."[47]

**Action Required to Fully Implement Recommendation 15.B.1:** No further action is needed.

**R15.B.2. In addition to requiring MISO to re-evaluate its operating agreements with member entities to verify its [MISO's] authority to address operating issues, NERC should require that any problems or concerns related to these operating issues be raised promptly with FERC and MISO's members for resolution.**

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[46] See http://www.nerc.com/~filez/remedialactionresponses.html, NERC Recommendation Verification Team MISO Report - July 12, 2004.

[47] Ibid., p. 8.

**Actions Taken:** NERC verified that MISO had the authority needed to address a variety of operating issues, and required that any problems related to the exercise of this authority be raised immediately with FERC and MISO's members.[48]

**Action Required to Fully Implement Recommendation 15.B.2:** No further action needed.

**R15.C. Corrective actions to be completed by PJM by June 30, 2004.**

In addition to requiring PJM to re-evaluate and improve its communications protocols and procedures for communications with neighbouring control areas and reliability coordinators, NERC should require PJM to standardize the definitions and usage of key terms, and minimize non-essential communications during disturbances, alerts, or emergencies. NERC should also require PJM, MISO, and their member companies to conduct one or more joint drills using the new communications protocols and procedures.

**Actions Taken:** NERC extended its February 10, 2004, directives to PJM to include the actions recommended by the Task Force.[49] PJM's President and CEO, Philip G. Harris, certified on June 30, 2004 that the actions required by NERC and recommended by the Task Force were implemented.[50]

**Action Required to Fully Implement Recommendation 15.C:** No further action needed.

**R15.D. Corrective actions to be completed by ECAR by August 14, 2004.**
**Note**: The Task Force acknowledges that the August 14, 2004 deadline proved to be unrealistic for some actions given the amount of work required.

**R15.D.1. NERC should require ECAR to re-evaluate its modeling procedures, assumptions, scenarios, and data for seasonal assessments and evaluation of extreme conditions. In doing so, ECAR should consult with an expert team appointed by NERC, joined by representatives from FERC, DOE, interested state commissions, and MISO.**

**Actions Taken:** On August 16, 2004, ECAR reported to NERC that the work on R15.D.1 was complete. The detailed report from ECAR is posted with other reports of remedial actions.[51]

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[48] Ibid., p. 8.
[49] See letter of May 14, 2004, from Michehl R. Gent, NERC President and CEO, to Philip G. Harris, President and CEO, PJM Interconnection, LLC. The letter is included in http://www.nerc.com/~filez/remedialactionresponses.html, PJM's Remedial Action Responses.
[50] Ibid.
[51] http://www.nerc.com/~filez/remedialactionresponses.html, ECAR's Remedial Action Responses.

**Action Required to Fully Implement Recommendation R15.D.1.** No further action is needed.

**R15.D.2. NERC should require ECAR to re-examine and validate all data and model assumptions against current physical asset capabilities and match modeled assets (such as line characteristics and ratings, and generator reactive power output capabilities) to current operating study assessments.**

**Actions Taken:** On August 15, 2005, ECAR advised NERC that its Transmission System Performance Panel had prepared a summary report for the ratings audits that were nearing completion. The best practices from those audits were presented at the June 2005 TSPP meeting and another presentation was scheduled for the October meeting. There were a total of six best practice presentations.[52]

The ECAR Transmission System Performance Panel (TSPP) issued its report of findings in October 2005 addressing Recommendation 15 D. 2. A copy was provided to NERC.

The TSPP conducted a one-day, on-site audit at each ECAR transmission owning Member and Reliability Coordinator (RC) from September through December 2004. One RC did not have a site visit, but was audited via mail and email. Audit sheets were completed for each Member and RC. The auditors reviewed their findings and provided a copy of the completed audit sheets to each Member and RC.

The audits addressed the following practices:

1. Transmission Line Conductor Rating Methodology – Overhead
2. Transmission Line Conductor Rating Methodology – Underground
3. Power Transformer Rating Methodology
4. Substation Bus Conductor Rating Methodology
5. Circuit Breaker Rating Methodology
6. Substation Bus Switch Rating Methodology
7. Transmission Line Switch Rating Methodology
8. Current Transformer Rating Methodology
9. Relay Rating Methodology - Thermal
10. Relay Rating Methodology - Trip Settings
11. Metering Rating Methodology
12. Wave Trap Rating Methodology
13. Rating Methodology for Other Series Elements
14. Database and/or Listing of Ratings for Each Circuit Element, including the most limiting element (this data shall not be a listing from a power flow base case)
15. Company Switching Diagram, showing connectivity of transmission facilities rated 100 kV and above (including substation shunt reactive devices, etc.)
16. Line and Transformer Impedance Calculation Methodology

[52] Ibid., p. 4.

17. Process for Determining Modeling Data for Shunt Reactive Devices for use in power flow base cases
18. Process for Updating System Modeling Data Based on Physical Equipment Updates Made in the Field
19. Process for Determining Real and Reactive Bus Loads Modeled in Power Flow Base Cases and How Bus Load Power Factor is Determined
20. Process for Communicating System Modeling Data (Impedances & Ratings) to Company Operators, RTO / RC, and Neighboring Control Areas.

As expected, no one company had all data and ratings match 100% throughout all locations checked in this audit. Reasons for this include round off or truncation of values, updates had not been propagated throughout all systems and databases, some data was taken from outdated sources, and data may have been used from different sources that did not agree. Some companies are in the midst of revising their methodologies and ratings, so ratings in base cases and other locations may not have agreed with the updated ratings in the circuit element lists. The ECAR TSPP will need to evaluate the findings of these audits to determine if any ECAR requirements or procedures will be needed to correct any areas for improvement.

The TSPP plans to use the findings of this audit process in the compliance monitoring realm in the future and may develop ECAR requirements to correct any deficiencies found. TSPP will not conduct follow-up audits as part of this process. However, ECAR will monitor the associated NERC standards for facility ratings and data through compliance monitoring and on-site compliance audits to verify that the Members are performing as required.



**Action Required to Fully Implement Recommendation 15.D.2:** Reliability*First*, should continue the work initiated by the ECAR TSPP until all blackout recommendations have been completed and a report to NERC regarding the data validation and exchange has been done.

NERC has advised that it will follow these recommendations to completion and make a final report to the U.S. DOE and Natural Resources Canada.

**R15.D.3. NERC should require ECAR to conduct a data validation and exchange exercise to be sure its members are using accurate, consistent, and current physical asset characteristics and capabilities for both long-term and seasonal assessments and operating studies.**

**Actions Taken:** On August 15, 2005, ECAR advised NERC that the ECAR Transmission System Performance Panel (TSPP) had sent a request for their members to conduct a system snapshot for the summer of 2005, perform a comparison of data to a power flow base case, and submit a summary report to ECAR by Sept. 9, 2005. A compendium report of all of those summaries will be produced by ECAR. ECAR will forward the completed summary and compendium report to NERC. ECAR expects to have this recommendation completed by the end of Sept. 2005, except for dynamic data, which will be handled later.[53]

The ECAR TSPP Model Benchmarking Team developed the criteria and a schedule for meeting the requirements of this recommendation. Each transmission-owning member company was required to “take a system snapshot” or record their system’s real-time data and quantities for a summer peak period, compare that information to a power flow base case, and summarize their findings in a report. ECAR forwarded a report to NERC in December 2005 that contains a compendium of member organization summaries and also documents the results of the ECAR TSPP’s efforts to respond to this recommendation.

The reexamination of dynamics data, which was begun by ECAR, will be completed by Reliability*First* (RFC). RFC will provide NERC with an expected completion date for this work.

**Action Required to Fully Implement Recommendation 15.D.3:** The actions noted must be completed and the dynamic data must be provided in a timely manner. Dynamic system data is critical for system performance. RFC should establish a completion date for this analysis that is acceptable to NERC.

**R15.E**. Corrective actions to be completed by other parties by June 30, 2004.

**R15.E.1. NERC should require each North American reliability coordinator, reliability council, control area, and transmission company not directly addressed above to review the actions required and determine whether it has adequate system facilities, operational procedures, tools, and training to ensure reliable operations for the summer of 2004. If any entity finds that improvements are needed, it should undertake them immediately, and coordinate them with its neighbours and partners as necessary.**

**Actions Taken:** On October 15, 2003, the NERC CEO wrote to the CEOs of all reliability coordinators and control areas regarding near-term actions as a result of the blackout. NERC requested each entity in North America that operates a control area and each NERC reliability coordinator to review a list of reliability practices to ensure their organizations are within NERC and Regional Reliability Council standards and established good utility practices. NERC further requested that within 60 days, each entity report in writing, with a copy to NERC, to their respective Regional Reliability Council that such a review had been completed and the status of any necessary corrective actions. All addressed entities responded to the actions requested in this letter.

NERC has included the issues identified in Recommendations 15.A-D in its Readiness Audit Program. NERC believes that the combination of its October 15, 2003, letter and the inclusion of these recommendations in its Readiness Audit Program provides

[53] NERC November 1, 2005 report to the Board of Trustees, Agenda Item 8, p. 4.

adequate assurance that these recommendations have been addressed by each North American reliability coordinator, reliability council, control area, and transmission company.[54]

**Action Required to Fully Implement Recommendation 15.E.1:** No further action needed.

**R15.E.2. FERC and government agencies in Canada should require all entities under their jurisdiction who are users of GE/Harris XA21 Energy Management Systems to consult the vendor and ensure that appropriate actions have been taken to avert any recurrence of the malfunction that occurred on FirstEnergy's system on August 14, 2003.**

**Actions Taken:** A FirstEnergy spokesperson was reported[55] to state that the utility applied fixes developed by General Electric (GE) for the XA21 EMS, and accelerated plans to replace this system with a system acquired from Areva SA. The spokesperson also stated that FirstEnergy, working with GE and KEMA, Inc., had by October 2003, determined the cause of the problem to be a software glitch which had been corrected by November 19, 2003. A GE spokesperson said the company distributed a warning and a fix to its more than 100 other customers the following day. The FirstEnergy spokesperson reported that FirstEnergy had informed[56] the Task Force at the time, and went public with the information in February 2004 in a report on the SecurityFocus web site.[57] The GE system at FirstEnergy was a 1996 model.

**Action Required to Fully Implement Recommendation 15.E.2:** No further action is needed.

**R16. Establish enforceable standards for maintenance of electrical clearances in right-of-way areas.**

In addition to NERC's requirements to report all bulk electric system transmission faults caused by vegetation and the development of minimum line clearances, the Task Force added four additional recommendations, R16.A-D.

**R16.A. Enforceable Standards**

**NERC should develop clear, unambiguous standards pertaining to maintenance of safe clearances of transmission lines from obstructions in the lines' right-of-way areas, and procedures to verify compliance with the standards. States, provinces,**

[54] Ibid., p. 4.
[55] USA Today, February 12, 2004.
[56] At the Task Force's Cleveland Workshop, July 15, 2004.
[57] http://www.securityfocus.com/news/8032.

**and local governments should remain free to set more specific or higher standards as they deem necessary for their respective areas.**

**Actions Taken:** NERC created an initial vegetation management standard and included it in the Version 0 NERC reliability standards approved by the NERC Board of Trustees at its February 2005 meeting. This Version 0 standard was considered preliminary by NERC, the industry, and regulators, and development of a new standard was subsequently initiated.

A comprehensive *Transmission Vegetation Management Program Standard* was successfully balloted and adopted by the NERC board on February 7, 2006, with an effective date of April 7, 2006. This standard is intended to improve the reliability of the electric transmission systems by eliminating transmission outages from vegetation located on transmission rights-of-way and minimizing outages from vegetation located adjacent to rights-of-way, maintaining safe clearances between transmission lines and vegetation on and along transmission rights-of-way, and establishing a system for reporting vegetation-related outages of the transmission systems (>200 kV) to the respective regional reliability councils and NERC.

The requirements included in the draft standard provide for each transmission owner to develop their own program reflecting the geographic and environmental conditions faced by them, including its particular transmission design policies and practices. The clearances specified by the standard are based on the Institute of Electrical and Electronics Engineers (IEEE) Standard, 516-2003, for flashover distances for various conditions and suggested ANSI Tree Care Standard (A300) as best practices. The intent of the draft vegetation management requirements is not to develop a *one-size-fits-all* standard, but to require each transmission owner to develop a program tailored to their circumstances and best allow them to meet the performance requirements associated with the NERC vegetation management standard. The plan is required to take into consideration the time required to obtain permission or permits from landowners or regulatory authorities, and to develop mitigation measures to achieve sufficient clearances for the protection of transmission facilities when it identifies locations on the right-of-way where the transmission owner is restricted from attaining the clearances specified in the standard.[58] [59]

**Action Required to Fully Implement Recommendation 16.A:** No further action required.

**R16.B. Right-of-Way Management Plan**

**NERC should require each bulk electric transmission operator to publish annually a proposed right-of-way management plan on its public web site, including a report on its right-of-way management activities for the previous year. The management**

[58] NERC November 1, 2005 report to the Board of Trustees, p. 8.
[59] Ibid.

**plan should include the planned frequency of actions such as right-of-way trimming, herbicide treatment, and the report should give the dates when the rights-of-way in a given district were last inspected and corrective actions taken.**

**Actions Taken:** NERC reports that it requires transmission owners to make vegetation management procedures and documentation of work completed available for review and verification upon request by the applicable Regional Reliability Council, NERC, or applicable federal, state, or provincial regulatory agency.[60]

**Action Required to Fully Implement Recommendation 16.B:** Note: NERC's action is not literally compliant with R16.B's requirement for the transmission owner to post a proposed right-of-way management plan on its web site and a report on its right-of-way management activities for the previous year. According to NERC, "many transmission owners believe that [such postings] would inappropriately place critical energy infrastructure information (CEII) into the public domain. Individual transmission owners have already filed their plans with FERC in response to FERC's one-time request, and a number of these filings requested CEII protection. The new NERC draft vegetation management standard requires the Regional Reliability Councils, as compliance monitors for this standard, to periodically audit the plans and activities of their transmission owners. All violations would be reported on NERC's web site as part of its quarterly compliance report."[61]

The Task Force recognizes the CEII issue. Therefore, no further action is required under this recommendation.

**R16.C. Requirement to report outages due to ground faults in right-of-way areas.**

**NERC should require each transmission owner/operator to submit quarterly reports of all ground-fault line trips, including their causes, on lines of 115 kV and higher in its footprint to the Regional Reliability Councils. Each council should provide a detailed annual report on ground-fault line trips and their causes in its area to FERC, NERC, DOE, appropriate authorities in Canada, and state regulators.**

**Actions Taken:** The Regional Reliability Councils have established reporting requirements for transmission owners on vegetation management, and have begun to file quarterly reports with NERC. Quarterly report filed with NERC shows continued evidence of contact between trees on rights-of-way and energized transmission line conductors in many areas of the Eastern and Western Interconnections in 2004 and in 2005. NERC has indicated that with additional years of data, it should be able to identify trends and problem areas.

[60] NERC November 1, 2005 report to the Board of Trustees, p. 5.
[61] Ibid., p. 9.

**Action Required to Fully Implement Recommendation 16.C:** No further action is needed.

**R16.D. Transmission-related vegetation management expenses, if prudently incurred, should be recoverable through electric rates.**

**Actions Taken:** FERC clarified in its April 19, 2004 policy statement that its existing policy to approve applications to recover prudently incurred vegetation management costs necessary to further safeguard the reliability and security of the energy supply infrastructure[62] extends to the recovery of prudent reliability vegetation management expenditures.[63]

Provincial regulatory bodies in Canada have issued similar statements.

**Action Required to Fully Implement Recommendation 16.D:** No further action is needed.

**R17. Strengthen the NERC Compliance Enforcement Program.**

**R17.A. In addition to requiring the regions to report all significant violations of NERC and regional standards to NERC within one month of the occurrence NERC should require the quarterly reports filed by the Regional Reliability Councils on violations of NERC and regional reliability standards to be filed as public documents with FERC and appropriate authorities in Canada, at the same time that they are filed with NERC.**

**Actions Taken:** At its June 15, 2004, meeting, the NERC Board of Trustees adopted, *Guidelines for Reporting and Disclosure* [of confirmed violations of standards], which call for public disclosure of violations via posting on NERC's web site. NERC also provides notice electronically to FERC, DOE, and the appropriate authorities in Canada of such postings, with links to the relevant documents. This action also covers R.17. C.

The quarterly compliance reports include reports on all confirmed violations, (i.e., violations for which the appeals process has been completed or the time for taking an appeal has passed). The quarterly reports include the identities of those organizations found to have violated NERC or regional standards. Compliance reports through the second quarter of 2005 are posted at: www.nerc.com/~comply/annual.html.[64]

**Action Required to Fully Implement Recommendation 17.A:** No further action is needed.

[62] Statement of Policy, 96 FERC ¶ 61,61,299 (2001)
[63] FERC Policy Statement at P 28.
[64] NERC November 1, 2005 report to the Board of Trustees, p. 10.

**R17.B. In addition to requiring the offending organizations to correct violations and if necessary seek assistance from appropriate regulators in dealing with non-responsive parties, NERC should inform the federal and state or provincial authorities of both countries of all enforcement proceedings and make the results of such proceedings public.**

**Actions Taken:** At present, NERC has no enforcement powers, although it has a procedure for assigning a hypothetical penalty for specific violations. However, FERC will certify a single ERO, to oversee the reliability of the United States' portion of the interconnected North American bulk power system, subject to FERC oversight. The ERO will be responsible for developing and enforcing the mandatory Reliability Standards.[65] Nevertheless, NERC has implemented significant improvements to its Compliance Enforcement Program.[66]

**Action Required to Fully Implement Recommendation 17.B:** To be implemented if and when FERC identifies NERC as the ERO pursuant to the U.S. Energy Policy Act of 2005.

**R17.C.** In addition to the reports required to be submitted by March or April 2004, and NERC recommendations to improve the compliance process, **NERC should make any findings and recommendations concerning violations of its standards on August 14 available to appropriate U.S. federal and state authorities, to appropriate authorities in Canada, and to the public.**

**Actions Taken:** The 2003 NERC Compliance Enforcement Program report, which is posted on the NERC website, includes the following discussion of the findings of violations of standards associated with the August 14, 2003 blackout:

> *NERC's Standards/Procedure and Compliance Investigation Team (SCIT) issued its final report on April 12, 2004. The SCIT reviewed NERC policies for violations using the root causes, confirmed deficiencies, and contributing factors identified by the Root Cause Analysis Team. Based on that review the SCIT identified a number of violations related to NERC Operating Policies 2, 4, 5, 6, 8, and 9. The affected Regions were asked to assess the violations, request mitigation plans, and monitor the progress in implementing these plans.*

See also R17.A.

**Action Required to Fully Implement Recommendation 17.C:** No further action needed.

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[65] FERC Order No. 672 at P 21.
[66] NERC November 1, 2005 report to the Board of Trustees, p. 10.

**R17.D**. **In addition to the NERC recommendation of Feb. 10, 2004, that required compliance (and readiness) audits of Control Areas be based on existing NERC control Area Certification Procedures and updated as new criteria are developed, the Task Force recommended that NERC standards be improved rapidly to make them clear, unambiguous, measurable, and consistent with the Functional Model.**

**Actions Taken:** In the interest of clarifying its existing policies and standards, NERC's Board approved the Version 0 NERC reliability standards in April 2004 consistent with the Functional Model. Work is underway to develop new standards and improve and strengthen many of the Version 0 NERC reliability standards as expeditiously as available resources allow until an ERO is certified by FERC. At that time, the ERO will be responsible for developing and enforcing the mandatory Reliability Standards.

**Action Required to Fully Implement Recommendation 17.D:** It is important that NERC continue to strengthen its reliability standards as expeditiously as possible until an ERO is certified.

**R17.E**. **This recommendation, associated with NERC Recommendation 3.C dealing with readiness audits, should have been included under Recommendation 18 which deals with readiness. See R17.E under R.18.**

**R17.F. NERC should require all compliance audit reports to be publicly posted, excluding portions pertaining to physical and cyber security according to predetermined criteria. Such reports should draw clear distinctions between serious and minor violations of reliability standards or related requirements.**

**Actions Taken:** The NERC Compliance and Certification Committee is currently developing a methodology to rank the severity of violations that will serve as a guide for developing appropriate sanctions. This effort has been incorporated into the Standards Development Process through a Standards Authorization Request. This will allow the methodology to be applied to each standard and allow industry input. The schedule for completion of the "violation risk factors" for each standard is the fall of 2006 in preparation for implementation of the ERO.

**Action Required to Fully Implement Recommendation 17.F:** This recommendation will be fully implemented when the Board approves the aforementioned procedures.

**R18. Support and strengthen NERC's Reliability Readiness Audit Program.**

**R18.A. NERC should conduct the remainder of the first-round reliability readiness assessments (i.e., for entities not covered in 2004) within two years, as compared to**

**the three-year plan adopted on February 10, 2004. Thereafter, all entities should be re-assessed on a three-year cycle.**

**Actions Taken:** During 2004, the first year of the Reliability Readiness Audit Program, NERC audited 61 control areas and six reliability coordinators which resulted in 643 recommendations. The audited entities and their Regional Reliability Councils have acted on at least 259 of these recommendations. To November 2005, Readiness Audit reports included 156 recommendations.

NERC advised that its Compliance and Certification Committee (CCC) reviewed the benefits and difficulties associated with the proposed change from the original three-year to a two-year implementation and recommended continuing with the original three-year schedule. The CCC does not believe there are appreciable reliability benefits to be gained by changing to a two-year cycle. Most industry practices assessed in a readiness audit do not change significantly over three years, so moving to a two-year cycle to audit these practices will result in assessing fewer changes. However, the CCC firmly supports auditing an entity sooner than three years to verify progress if the previous audit uncovered conspicuous deficiencies. A copy of the position paper approved by the CCC at its December 13–14, 2004, meeting appears on the CCC web site.

NERC also advises that it is developing a tracking mechanism to monitor actions on the recommendations and that if the number of open recommendations grows, or is not more rapidly reduced, NERC will request that the regions address this issue.

**Action Required to Fully Implement Recommendation 18.A:** The Task Force reluctantly accepts NERC's rationale for retaining the three-year cycle. However, NERC should assess and rank the importance of the outstanding Readiness Audit recommendations and take action to ensure that they are implemented expeditiously.



**R18.B. NERC should require all readiness assessment reports to be publicly posted, excluding portions pertaining to physical and cyber security. Reports should also be sent directly to DOE, FERC, relevant authorities in Canada, and relevant state commissions.**

**Actions Taken:** The NERC Board of Trustees, at its June 2004 meeting, decided to make the final reports from all such assessments public by posting them on NERC's web site. A number of regulators and other recipients have asked not to be sent these detailed reports. NERC stated that it would develop a new procedure to identify appropriate regulatory agencies to receive these reports.[67]

**Action Required to Fully Implement Recommendation 18.B:** Completion and approval of the new procedure to identify appropriate regulatory agencies to receive reports.

[67] Oral advice from D. Hilt, VP Compliance, NERC, to T. Rusnov, Sr. Advisor, NRCan, Aug. 16, 2005.

**R17.E[68] In addition to NERC Board of Trustees approval that the Regional Reliability Councils have primary responsibility for conducting the compliance audits, and that FERC and other relevant regulatory agencies should be invited to participate in these audits, subject to the same confidentiality conditions as the other audit team members, each team should have some members who are reliability experts from outside the region being audited, and some members should be relevant experts from outside the electricity industry.**

**Action Taken**: NERC includes on its readiness audit teams, electric reliability experts from outside the region in which the audit is occurring, as well as one team member from a separate Interconnection. FERC staff from the Division of Reliability has also participated in many of the reliability readiness audits as well as representatives from the Institute of Nuclear Power Operations (INPO). Several audit team leaders have had orientation and training in the INPO audit process. In addition, several of the regional compliance managers came from other industries where they had experience conducting similar kinds of audits.

**Action Required to Fully Implement Recommendation 17.D:** No further action is needed.

**R19. Improve near-term and long-term training and certification requirements for operators, reliability coordinators, and operator support staff.**

In addition to other training requirements and NERC's February 10, 2004, requirement that all reliability coordinators, control areas, and transmission operators are to provide at least five days per year of training and drills in system emergencies—using realistic simulations—for each staff person with responsibility for the real-time operation or reliability monitoring of the bulk electric system, the Task Force recommended that:

**R19.A. NERC should require training for the planning staff at control areas and reliability coordinators concerning power system characteristics and load, VAR, and voltage limits, to enable them to develop rules for operating staff to follow.**

**Actions Taken:** NERC is addressing all parts of R19 as an integrated training and certification program. NERC's Standards Authorization Committee (SAC) accepted the Standards Authorization Request (SAR) for developing a System Personnel Training Standard. NERC is currently soliciting drafting team members to draft this standard, which will require the use of a systematic approach to determining training needs:. The standard will require each Reliability Coordinator, Balancing Authority and Transmission Operator to:



[68] Recommendation 17.E in the Task Force report was incorrectly grouped with recommendations pertaining to the Compliance Enforcement Program instead of the Readiness Audit Program.

- Identify the desired performance for each real-time, reliability-related task performed by its real-time system operators;
- Measure the mismatch between actual and desired performance, and
- Use the results of the mismatch between desired and actual performance as the basis for determining training needs, developing, delivering and evaluating training.

The standard will require that entities have evidence that this systematic approach to training was conducted and used as the basis for providing training. The proposed standard will also require that each responsible entity have evidence that each of its real-time system operators is competent to perform each assigned task that is on its company-specific list of reliability-related tasks.

**Action Required to Fully Implement Recommendation 19.A:** The recommendation will be fully implemented when the NERC Board of Trustees approves the standards for modeling and analysis requirements, the certification requirements for reliability coordinators, balancing authorities and transmission operators, and the overall operator training program.

**R19.B. NERC should require control areas and reliability coordinators to train grid operators, IT support personnel, and their supervisors, to recognize and respond to abnormal automation system activity.**

**Actions Taken:** NERC has launched an operator training initiative, which will include standards for operator and support staff training programs. It expects the training program objectives and the standards for training programs to be in place by mid-2006. (See discussion under R19.C.) The development process and elements of the training standard may be seen at: http://www.nerc.com/%7Efilez/standards/System-Personnel-Training.html.

**Action Required to Fully Implement Recommendation 19.B:** Establishment of the aforementioned training standards and training programs.

**R19.C. NERC should commission an advisory report by an independent panel to address a wide range of issues concerning reliability training programs and certification requirements.**

**Actions Taken:** NERC has commissioned an independent expert from the U.S. Navy Human Performance Center to aid in the development of a comprehensive training program with curriculum requirements and other standards, not just a training study. The program objectives, including standards for training programs, are expected to be completed by mid 2006. Reports on the scope and status of this initiative have been made to the NERC Board of Trustees on a regular basis, and are available in posted board agendas and minutes.

**Action Required to Fully Implement Recommendation 19.C:** Completion and approval of the comprehensive training program and standards will constitute full implementation.

**R20. Establish clear definitions for *normal, alert,* and *emergency* operational system conditions. Clarify roles, responsibilities, and authorities of reliability coordinators and control areas under each condition.**

**Actions Taken:** NERC's Reliability Coordinator Working Group (RCWG) has developed definitions of normal, alert, and emergency conditions for use as a pilot program for reporting on the Reliability Coordinator Information System (RCIS) during summer 2006.

The reliability coordinators are taking a cautious approach because simple terms don't convey the nuances that are truly important for deciding what actions to take. Also, in some cases, these definitions are not consistent with those used internally by various ISOs and RTOs, and which appear in their tariffs.

**Action Required to Fully Implement Recommendation 20:** With completion and approval of the actions noted, R20 will be fully implemented.

**R21. Make more effective and wider use of system protection measures.**

**R21.A.** In addition to reviewing Zone 3 relays on lines 230kV and above, **NERC should require all transmission owners to broaden their review of the settings of Zone 3 relays to include operationally significant 115 kV and 138 kV lines, e.g., lines that are part of monitored flow gates or interfaces. Transmission owners should also look for Zone 2 relays set to operate like Zone 3 relays.**

**Actions Taken:** The NERC System Protection and Control Task Force (SPCTF) completed its review of Zone 3 relay loadability on July 1, 2005. This review included almost 11,000 circuit terminals.

NERC also broadened its review of Zone 3 relay applications to include the lower voltage lines recommended and a review of second stage protection systems as described in the recommendations of the SPCTF.[69] These recommendations were endorsed by the NERC Planning Committee and approved by the NERC Board of Trustees on August 2, 2005.

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[69] ftp://www.nerc.com/pub/sys/all_updl/docs/bot/Agenda-Items-0805/Item8a-Attach1.pdf

During the analysis of the August 2003 blackout, a number of other relay loadability issues were identified that SPCTF believes should also be reviewed. SPCTF's *Protection System Review Program – Beyond Zone 3* action plan, which was approved by the Planning Committee in June 2005, addresses the additional loadability issues for extra high voltage (EHV) circuits 200 kV and above, as well as operationally significant circuits 100 kV and above.

Transmission System Protection Owners (TSPOs) are scheduled for completion of relay review circuits 200 kV and above by June 30, 2006, and mitigation by December 31, 2007. For operationally significant circuits 100 kV and above, it calls for review and completion by December 31, 2006, and mitigation by June 30, 2008. A rough estimate of circuit terminals to be reviewed at this voltage level is between 20,000 and 30,000, necessitating the length of the review and mitigation schedule.

In December 2005, the NERC Planning Committee (PC) approved a white paper providing the engineering basis for a proposed standard on relay loadability, culminating a major project to analyze the performance of existing protection systems and to research preferred set points to ensure that protection systems and settings do not limit transmission loadability, or contribute to cascading outages. The PC also approved a draft Standards Authorization Request (SAR) developed by its System Protection and Control Task Force (SPCTF) to develop a standard on relay loadability.

This proposed standard will address the cascading transmission outages that occurred in the August 2003 blackout when backup distance and phase relays operated on high loading and low voltage without electrical faults on the protected lines. This is the so-called 'zone 3 relay' issue, which has been expanded to address other protection devices subject to unintended operation during extreme system conditions. The proposed standard will establish minimum loadability criteria for these relays to minimize the chance of unnecessary line trips during a major system disturbance.

The NERC Standards Authorization Committee (SAC) approved the SAR on relay loadability and on April 21, 2006, issued a request for drafting team members. A first draft of the standard is expected to be posted in mid-July 2006.

**Action Required to Fully Implement Recommendation 21.A:** The specific requirements of R21.A have been met and no further action to implement it is required beyond that included in the SPCTF Report and the action by the Planning Committee to develop a standard on relay loadability. The Task Force commends NERC for initiating development of a standard in this area.

**R21.B. In addition to the requirements for each Regional Reliability Council to evaluate and report on the feasibility and benefits of under-voltage load shedding (UVLS) capability in its load centers, NERC should require the results of the regional studies to be provided to federal and state or provincial regulators at the same time that they are reported to NERC. In addition, NERC should require**

**every entity with a new or existing UVLS program to have a well-documented set of guidelines for operators that specify the conditions and triggers for UVLS use.**

**Actions Taken:** At its February 2006 meeting, the NERC board approved a resolution to implement the recommendations of the *Review of Regional Evaluations of Undervoltage Load Shedding Capability in Response to NERC Blackout Recommendation 8b* report, which was developed by the NERC Planning Committee. The board resolution:

- Directs the Planning Committee to develop by the end of 2006 a comprehensive set of study guidelines for use in future evaluations of the need and benefit of implementing undervoltage load shedding (UVLS) systems;
- Requests each regional reliability council, in conjunction with its members, to develop implementation plans and schedules to install UVLS capability in those load centers where regional studies have identified UVLS as feasible and beneficial to preventing instability and to provide these plans and schedules to the Planning Committee for review by June 2006;
- Directs the Planning Committee to review and report to the board at its August 2006 meeting on the regional UVLS implementation plans and schedules;
- Directs the Planning Committee to survey the existing UVLS systems installed on the bulk power system, to continue to monitor future installations, and support potential future standards activities in this area; and
- Directs the Planning Committee to survey the status of research and development efforts on methods to more accurately determine and model load characteristics and to report to the board at its November 2006 meeting on the results of those efforts.

**Action Required to Fully Implement Recommendation 21.B:** No further action needed.

**R21.C. In its planned review of Planning Standard III, which covers the use of relays, UVLS, and other system protection measures, NERC should determine the goals and principles needed to establish an integrated approach to relay protection for generators and transmission lines and the use of load-shedding programs.**

**Actions Taken:** At its December 2005 meeting, the NERC Planning Committee approved the recommendations of its Blackout Recommendations Review Task Force. The task force was formed to review the technical team's 24 recommendations, 13 of which confirm or strengthen several NERC and U.S.-Canada Power System Outage Task Force August 14, 2003 blackout recommendations that are currently being addressed and 11 of which are new technical recommendations. The task force also developed an assignment matrix as to which subgroups of the Planning Committee and Operating Committee should be involved with addressing the 24 recommendations.

**Action Required to Fully Implement Recommendation 21.C:** Completion of the work recommended by the Planning Committee and approval by the NERC Board of Trustees will constitute full implementation. The Task Force commends NERC for extending its actions beyond the original recommendations.

**R22. Evaluate and adopt better real-time tools for operators and reliability coordinators.**

This recommendation had two components:

**R22.A. In addition to requiring its Operating Committee to evaluate the real-time operating tools necessary for reliable operation and reliability coordination, including backup capabilities, NERC should require the Operating Committee to give particular attention in its report to the development of guidance to control areas and reliability coordinators on the use of wide-area situation visualization display systems and the integrity of data used in those systems.**

**Actions Taken:** FERC sponsored a technical conference on July 14, 2004 on Information Technology for Reliability and Markets. At that conference, FERC staff presented its views on minimum requirements and best practices for reliability software for the purpose of initiating industry discussion on what these minimum reliability capabilities ought to be. This information was forwarded to the NERC Real-Time Tools Best Practices Task Force (RTTBP) established by the NERC Operating Committee. The RTTBP Task Force was created to give particular attention to tools that would enhance operators' situational awareness.

The RTTBP Task Force finalized a reliability tools best practices survey, which was sent to Lawrence Berkley National Laboratory for programming as a web-based survey. A copy of the survey is posted for information. The web-based survey was made available to respondents in September with responses due in October. The areas addressed by the survey are:

- Real Time Data Collection
- Reliability Tools for Situational Awareness
- Operating Practices
- Modeling Practices
- Tools Used for Support and Maintenance

The survey is designed to allow the respondents to identify what they believe to be *best practices* in their control center regarding a host of operating tools—contingency analysis, optimal power flow, reactive control, etc. Following a review of the survey responses, the Task Force will, using its collective judgment, attempt to identify those operating entities that are using or proposing to use a *best practice*. The Task Force will conduct a follow-up interview with specific respondents to gather additional information related to the best practice for documentation purposes. The final product of this project will be a list of *best practices* for situational awareness. The final report of the Task Force is scheduled for submission to the Operating Committee in September 2006. The report will make recommendations on revisions to existing standards, development of new standards, and development of best practices or operating guides.

Based on the success of this project, the Operating Committee will consider keeping these *best practices* updated and forming a permanent working group, or assigning them to one if its subcommittees. NERC also has another group that is investigating the merits of developing *best practices* in general.

NERC is working with the DOE through the Consortium for Electric Reliability Technology Solutions (CERTS) on the development and implementation of the Eastern Interconnection Phasor Project (EIPP). The Western Electricity Coordinating Council's (WECC) existing Wide Area Measurement System and the new EIPP include installation of high-speed measurement devices and analysis tools that will provide operators with a new class of operational visibility and situational awareness. Such measurements would be incorporated into a *defense in depth* measurement and an alarming and backstop system to help reduce the likelihood of future blackouts.

Currently, there are over 50 Phasor Measurement Units (PMUs) in the Eastern Interconnection, with 20 additional units planned for installation in 2006. Of the 50 existing PMUs, 34 are connected to the Super Phasor Data Concentrator (SPDC) located at Tennessee Valley Authority, with 11 more awaiting integration. The PMUs are streaming real-time data to the SPDC and some of the real-time tools are in beta testing. Development has begun on incorporating angular separation alarming into the real-time tools to enhance reliability coordinator situational awareness. Additional measurement points are needed throughout the Eastern Interconnection to provide the necessary observability. EIPP is also working cooperatively with WECC's WAMS project to address real-time observability in WECC. Within the next year, the Eastern Interconnection will have a production-grade suite of real-time tools based on the EIPP.

**Action Required to Fully Implement Recommendation 22.A:** Completion of a set of best practices and their approval by the NERC Board of Trustees will constitute partial completion of the recommendation. Implementation of the EIPP project will constitute full implementation. NERC should develop and publish an implementation plan and schedule for the best practices and the EIPP project.

**R22.B.1 Operating Committee should prepare its report in consultation with FERC, appropriate authorities in Canada, DOE, and the Regional Reliability Councils. The report should also inform actions by FERC and Canadian government agencies to establish minimum functional requirements for control area operators and reliability coordinators.**

**Actions Taken:** NERC questioned the need for FERC or Canadian government agencies to establish their own minimum functional requirements for control area operators or reliability coordinators. The Task Force accepts NERC's position given the following:

To demonstrate that entities registered with NERC—Reliability Coordinators, Balancing Authorities, Transmission Operators, etc.—have at least the minimum capabilities needed to carry out their respective functions, NERC is developing Organization Certification Standards that will include requirements for those entities that are registered with it. Since these standards will be developed through NERC's standards development process, there will be an opportunity for interested regulatory authorities to participate. Further, as mandatory reliability standards are implemented in the United States and Canada, there will be opportunity for regulatory authorities to approve Organization Certification Standards or remand these standards back to the reliability organization for further consideration

**Action Required to Fully Implement Recommendation 22.B.1:** The recommendation will be fully implemented with the NERC Board's approval of the Organization Certification Standards.

**R22.B.2. That FERC, DHS, and appropriate authorities in Canada should require annual independent testing and certification of industry EMS and supervisory control and data analysis (SCADA) systems to ensure that they meet the minimum requirements envisioned in R3.**

**Actions Taken:** NERC expects that electric industry organizations will comply with all NERC reliability standards and it will certify those organizations to ensure that they do comply. NERC's compliance and certification requirements will themselves require reliability coordinators, transmission operators, and balancing authorities to have adequate EMS and SCADA systems. Further, the reliability readiness audits will provide a sufficient evaluation of these capabilities. Accordingly, NERC does not agree that conducting independent testing of those systems is necessary or appropriate.

**Action Required to Fully Implement Recommendation 22.B.2:** The Task Force accepts NERC's rationale regarding independent testing provided these systems are explicitly addressed during NERC's readiness and compliance audits.

**R23.1. Strengthen reactive power and voltage control practices in all NERC regions.**

**In addition to NERC's requirements of February 10, 2004 that nine of the ten Regional Reliability Councils re-evaluate within one year their implementation of existing reactive power and voltage control, ECAR was to complete its review by June 30, 2004. NERC should require the regional analyses to include recommendations for appropriate improvements in operations or facilities, and to be subject to rigorous peer review by experts from within and outside the affected areas.**

**Actions Taken**: The Planning Committee's TIS surveyed the regions, summarized their current practices and developed recommendations for new or revised standards and procedures for reactive power and voltage control standards. In May 2005, the NERC Board of Trustees accepted the report from the Planning Committee's TIS, *Evaluation of Reactive Power Planning and Voltage Control Practices*, and initiated a number of actions to implement recommendations in that report. In addition to responding to the NERC survey, several regions have created task forces to begin development of regional criteria.

At its February 2006 meeting the NERC Board of Trustees approved standards for Verification of Generator Gross and Net Reactive Power Capability and Undervoltage Load Shedding Program Data and Performance. Standards on Voltage and Reactive Control and Generator Operation for Maintaining Network Voltage Schedules are posted for pre-ballot review.

In addition, ECAR contracted with a vendor to conduct a voltage/reactive study to help in establishing regional voltage/reactive criteria. The final vendor report was completed on October 10, 2005.

**Action Required to Fully Implement Recommendation 23 (1):** Approval of the remaining standards by the NERC Board of Trustees in this area will fully implement this recommendation.

**R23.2. The Task Force also recommended that FERC and appropriate authorities in Canada should require all tariffs or contracts for the sale of generation to include provisions specifying that the generators can be called upon to provide or increase reactive power output if needed for reliability purposes, and that the generators will be paid for any lost revenues associated with a reduction of real power sales attributable to a required increase in the production of reactive power.**

**Actions Taken:** All Canadian provincial regulators have processes in place to ensure that generators provide the required VAR support, as directed by their system operators. In the United States, on July 24, 2003, FERC issued an order for large generators (>20MW) that want to interconnect to a public utility's transmission system.[70] A subsequent order for small generators was issued on March 5, 2004.[71] The orders specify that to help preserve reliability, interconnected generators can be called upon to provide, and be compensated for, increased reactive power when requested by the Transmission Provider for reliability purposes.

[70] Standardization of Generator Interconnection Agreements and Procedures (Order 2003), 104 FERC ¶ 61,103 (2003).
[71] Standardization of Generator Interconnection Agreements and Procedures (Order 2003-A), 106 FERC ¶ 61,220 (2004).

Additionally, FERC staff conducted a workshop on March 8, 2005 to discuss issues raised in the FERC staff report regarding reactive power supply for the nation's bulk-power supply.[72] The workshop included representatives from the industry.

**Action Required to Fully Implement Recommendation 23.2:** No further action is needed.

**R24. Improve the quality of system modeling data and data exchange practices.**

**In addition to NERC's requirements of February 10, 2004 calling for the Regional Reliability Councils to establish and implement criteria for validating data used in power flow models, benchmarking model outputs against actual system performance; and exchanging that validated data between regions as needed for reliable system planning and operations, FERC and appropriate authorities in Canada should require all generators, regardless of ownership, to collect and submit generator data to NERC, using a regulator-approved template.**

**Actions Taken:** At its May 2006 meeting, the NERC Board of Trustees approved two standards that address system modeling and data reporting requirements: Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedure and Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management, both of which become effective November 2, 2006.

**Action Required to Fully Implement Recommendation 24**: NERC believes that it can obtain the generator data needed without direct involvement of regulators. However, generator data is only one part of a complex set of data necessary to adequately model system performance.

The Task Force recognizes that Power System Modeling is a complex endeavour involving an ongoing exercise and requiring constant development of new technologies. As such, the Task Force encourages NERC to continue working expeditiously with the regions and industry to develop better modeling methodologies which include improved data collection and validation and the incorporation of these into NERC's proposed new MOD standards.

**R25. NERC should re-evaluate its existing reliability standards development process and accelerate adoption of enforceable standards.**

This recommendation had four components A, B, C, and D, which NERC has addressed in one integrated effort:

[72] Principles for Efficient and Reliable Reactive Power Supply and Consumption, Staff Report, Docket No. AD05-1-000, February 4, 2005.

**R25.A. NERC should re-examine its existing body of standards, guidelines, etc., to identify those that are most important and ensure that all concerns that merit standards are addressed in the plan for standards development.**

**R25.B. NERC should re-examine its plan for standards development to ensure that those that are the most important or the most out-of-date are addressed early in the process.**

**R25.C. NERC should build on existing provisions and focus on what needs improvement, and incorporate compliance and readiness considerations into the drafting process.**

**R25.D. NERC should re-examine the Standards Authorization Request process to determine whether, for each standard, a review and modification of an existing standard would be more efficient than development of wholly new text for the standard.**

**Actions Taken:** At its June 15, 2004, meeting, the NERC Board of Trustees adopted an accelerated plan to re-state its existing reliability standards in clear and readily enforceable terms—the Version 0 NERC reliability standards. At its February 2005 meeting, the NERC Board of Trustees adopted the Version 0 reliability standards effective April 1, 2005. The NERC Board, at its August 2, 2005, meeting approved a number of significant revisions to the *NERC Reliability Standards Process Manual.* These revisions are aimed at streamlining and clarifying the standards development process and directly addressing Recommendation 25 of the Final Blackout Report.

NERC is responding separately to the FERC staff assessment of the reliability standards NERC filed with its ERO application, and will participate in the technical conference scheduled for July 2006.

In addition, as discussed in several preceding recommendations, NERC task forces are identifying best practices in several areas, which may lead to either the upgrading of existing standards or the development of standards in new areas.

**Action Required to Fully Implement Recommendation 25:** No further action is needed.[73]

**Note:** This recommendation focused on a comprehensive review and improvement by NERC of its standards-setting process. It was not intended to encompass the full development of new standards in areas where needed.

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[73] NERC November 1, 2005, report to the Board of Trustees, p. 26.

**R26. Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communications hardware where appropriate.**

**Actions Taken:** NERC installed a new conference bridge and approved a new set of hotline procedures and protocols for reliability coordinator hotline calls.

NERC is also working on an upgrade of the Reliability Coordinator Information System (RCIS). This on-line, real-time, messaging system connects all reliability coordinators and many control areas. It also enables reliability coordinators to share emergency alerts, display Area Control Error (ACE) information, frequency, and selected outages. Work in this area will be an ongoing activity as technologies and techniques improve. The RCIS has already had a minor upgrade, with more expected by the end of the year.

The System Data Exchange (SDX) facility has been significantly enhanced since August 2003, including requirements for hourly uploads of outage data. Many of the uploads are now automated and SDX data is automatically *ported* to the RCIS. Most of that work was completed prior to June 2004.

**Action Required to Fully Implement Recommendation 26:** No further action is needed.

**R27. Develop enforceable standards for transmission line ratings. NERC should develop clear, unambiguous requirements for the calculation of transmission line ratings (including dynamic ratings), and require that all lines of 115 kV or higher be re-rated according to these requirements by June 30, 2005.**

**Actions Taken:** At its February 2006 meeting, the NERC board approved the following standards associated with facility ratings: Facility Ratings Methodology (to be effective on May 1, 2006), Establish and Communicate Facility Ratings (to be effective on July 1, 2006), Transfer Capability Methodology (to be effective on May 1, 2006) and Establish and Communicate Transfer Capabilities (to be effective on July 1, 2006).

**Action Required to Fully Implement Recommendation 27:** No further action needed.

**R28. Require use of time-synchronized data recorders.**

In its requirements of February 10, 2004, NERC directed the Regional Reliability Councils to define, within one year, regional criteria for the application of synchronized recording devices in key power plants and substations. The Task Force supported this recommendation strongly, but recommended a broader approach with four components.

**R28.A. FERC and appropriate authorities in Canada should require the use of data recorders synchronized by signals from the Global Positioning System (GPS) on all categories of facilities whose data may be needed to investigate future system disturbances, outages, or blackouts.**

**Actions Taken:** These requirements have been adopted by NERC, the Regional Reliability Councils and industry, as reflected by the work noted under R28.B & C.

**Action Required to Fully Implement Recommendation 28.A:** No further action is needed.

**NERC has addressed R28.B and R28.C as a single endeavour.**

**R28.B. NERC, reliability coordinators, control areas, and transmission owners should determine where high-speed power system disturbance recorders are needed on the system, and ensure that they are installed by December 31, 2004.**

**R28.C. NERC should establish data recording protocols.**

**Actions Taken***:* NERC's Interconnection Dynamics Working Group (IDWG) has examined NERC's standards on disturbance monitoring as well as existing interconnection-wide practices and concluded that the NERC DME standards and related regional requirements are inadequate. In response, the IDWG developed a set of recommendations for specific improvements that are included in its report, *Review of Regional Disturbance Monitoring Equipment*, which addresses both the NERC and U.S.-Canada Task Force recommendations. The Planning Committee approved IDWG's report at its March 2005 meeting and the NERC Board of Trustees accepted the report at its May 2005 meeting.

The Task Force recognizes that its target completion date of December 31, 2004, was unrealistic, given the amount of work to be done.

Two new standards – Define Regional Disturbance Monitoring and Reporting Requirements, and Disturbance Monitoring Equipment Installation and Data Reporting – were posted for a 30-day pre-ballot review through June 14, 2006.

A proposed new standard, to be drafted in 2006 and approved in 2007, will set requirements for the real-time monitoring and recording of system performance using phasor measurement devices. The August 2003 blackout proved the value of such devices in analyzing the causes and failure modes of major system disturbances.

**Action Required to Fully Implement Recommendation 28.B & C:** These recommendations will be fully implemented when the NERC Board of Trustees approves the aforementioned standards.

**R28.D.FERC and appropriate authorities in Canada should ensure that the investments called for in this recommendation will be recoverable through transmission rates.**

**Actions taken:** FERC and appropriate authorities in Canada have addressed this concern through more generic actions. (See discussion under R4, pp. _______.)

**Action Required to Fully Implement Recommendation 28.D:** No further action needed.

**R29. Evaluate and disseminate lessons learned during system restoration.**

**Actions Taken:** In response to direction from the NERC Board, ECAR, NPCC, and MAAC each prepared reports explaining how their system operators restored the bulk electric system in their region after the blackout. Each region's report included recommendations for improving preparedness and the system restoration process. All regions are now reviewing their blackstart and system restoration plans and procedures, and making necessary revisions.

**Action Required to Fully Implement Recommendation 29:** No further action needed.

**R30. Clarify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages.**

**NERC should work with the control areas and reliability coordinators to clarify the criteria for identifying critical facilities whose operational status can affect the reliability of neighboring areas, and to improve mechanisms for sharing information about unplanned outages of such facilities in near real-time.**

**Actions Taken:** The NERC Operating Committee's Operating Limits Definition Task Force (OLDTF) has developed a draft technical document that is being used by reliability coordinators. This document provides approaches through which excellence in system reliability can be achieved for the application of reliability standards as they pertain to Interconnection Reliability Operating Limits (IROL). This document includes a definition of a critical facility or element covering both SOL and IROL values. The *Reliability Coordinator Reference Document - System Data Exchange (SDX) – Eastern Interconnection Only*, defines the method and frequency for submittal of operational data required for ATC calculations and the NERC transmission loading relief (TLR) application, the IDC, and power system studies.

The risk of inadvertent disclosure of CEII is an ongoing concern that must be taken into account.

**Action Required to Fully Implement Recommendation 30:** Finalize and obtain approval of the IROL technical document and ensure it is being properly interpreted and used.

**R31. Clarify that the TLR process should not be used in situations involving an actual violation of an Operating Security Limit. Streamline the TLR process.**

**Actions Taken:** NERC's Operating Committee rewrote several of NERC's operating policies to address these issues. These changes have been incorporated into NERC's Version 0 reliability standards.

**Action Required to Fully Implement Recommendation 31:** No further action needed.

## Group III: Recommendations to Enhance the Physical and Cyber Security of North American Bulk Power Systems
*(Recommendations 32 through 44)*

**Summary:** The recommendations in this section of the report address both the physical and the cyber security of the North American electrical system.

In the United States, the enactment of EPAct 2005 established a legal framework for the certification by FERC of an ERO. The ERO will be responsible for the development and enforcement of FERC approved mandatory Reliability Standards. In Canada, the Council of Energy Ministers (Federal-Provincial-Territorial) endorses the Task Force recommendations on the implementation of mandatory standards, and has directed a working group to work with key stakeholders to develop a framework to ensure identical or compatible reliability standards in both countries. Development of new security guidelines to help protect the electricity infrastructure has been an ongoing area of activity for NERC's CIPC and will be an ongoing area of activity for the ERO.

**TABLE 3.3: Summary of Implementation Status of Recommendations 32 to 44**

| Recommendation Number | Fully Implemented | | Not Yet Fully Implemented | Entity Responsible for Full Implementation |
|---|---|---|---|---|
| | One-Time Action | Ongoing Activity | | |
| R32A | | x | | NERC |
| R32B | | x | | Control areas and reliability coordinators |
| R33 | | x | | Control areas and reliability coordinators |
| R34 | | x | | Control areas and reliability coordinators |
| R35 | | x | | Control areas and reliability coordinators |
| R36 | | x | | U.S. and Canadian Federal agencies |
| R37 | | x | | Control areas and reliability coordinators |
| R38 | | x | | IT and EMS personnel |
| R39 | | x | | Control areas and reliability coordinators, private and public sectors |
| R40 | | x | | Control areas and reliability coordinators NERC |
| R41 | | x | | NERC |
| R42 | | x | | Private and public sectors |
| R43 | | x | | Corporations |
| R44 | | x | | Private and public sectors |
| **Totals** | **14** | | **0** | |

Note: After the certification of an ERO, the entity responsible for recommendations that will be implemented with the development of a standard will be the ERO.

**R32. Implement NERC IT standards.**

**The Task Force recommends that NERC standards related to physical and cyber security should be understood as being included within the body of standards to be made mandatory and enforceable in Recommendation No. 1.**

The recommendation had two components:

**R32.A NERC should ensure that the industry has implemented its Urgent Action Standard 1200; finalize, implement, and ensure membership compliance with its Reliability Standard 1300 [CIP-002-1 through CIP-009-1] for Cyber Security and take actions to better communicate and enforce these standards.**

**Actions Taken:** NERC is the lead agency in this area as well as one of the key players in efforts to ensure that the bulk electric system in North America is reliable, adequate and secure. Representatives from the Canadian bulk electricity system entities actively participate in the Canadian Electricity Association (CEA) – Critical Infrastructure Protection Working Group and the NERC CIPC. The mandate of the CEA working group and the NERC committee is the development, continuous improvement, and the promotion of the adoption of physical and cyber security measures.

The NERC Urgent Action Cyber Security Standard was established in August 2003 as an interim standard and included requirements for:

- Corporate security strategy and governance;
- Periodic assessment of risks and vulnerabilities;
- Monitoring and controlling access;
- Employee background screening; and
- Clear accountability for cyber and physical security.

On May 2, 2006, the NERC Board of Trustees voted to accept Critical Infrastructure Protection (CIP)-002 through CIP-009 standards. These standards became effective June 1, 2006, at which time the Urgent Action 1200 standard was superseded.

In addition to the aforementioned requirements, the permanent Cyber Security Standards address requirements for:

- Data and information classification according to confidentiality;
- Identification and protection of critical cyber assets related to the reliable operation of the bulk electric systems; and
- Process control and Supervisory Control and Data Acquisition Systems (SCADA).

**Action Required to Fully Implement Recommendations 32.A:** NERC has approved the permanent Cyber Security Standard. As of May 25, 2006, the CIP-002 through CIP-

009 standards have not been submitted by NERC to FERC for approval as reliability standards. When the subject standards are submitted, FERC will start the process of public comment and determine whether the standards should be accepted and approved.

**R.32B Control areas and reliability coordinators should implement existing and emerging NERC standards, develop and implement best practices and policies for IT and security management, and authenticate and authorize controls that address EMS automation system ownership and boundaries.**

**Actions Taken:** The NERC CIPC Outreach Working Group has conducted three workshops to aid in the compliance with the NERC Urgent Action Standard.

The standard called for substantial compliance by January 1, 2004, and full compliance by January 1, 2005. The NERC CEP completed its second round of monitoring compliance with the urgent action cyber security standard 1200 as of the beginning of 2005. The specific results are classified as Critical Energy Infrastructure Information and are being shared confidentially with the Compliance Committee of the Board.

**Action Required to Fully Implement Recommendations 32.B.:** The development of new security guidelines to help protect the electricity infrastructure, including the training and dissemination of best practices has been an ongoing area of activity for NERC CIPC and will be an area of ongoing activity for the ERO. The ERO will assume a monitoring and reporting role with respect to the implementation of the recommendations. This is a critical infrastructure security issue and NRCan and DOE, in consultation with other key stakeholders will continue to monitor the situation and the industry's implementation of the new standards. This is in keeping with their ongoing responsibilities for the protection of critical cross-border energy infrastructure.

**R33. Develop and deploy IT management procedures.**

**Control areas' and reliability coordinators' IT and EMS support personnel should develop procedures for the development, testing, configuration, and implementation of technology related to EMS automation systems and also define and communicate information security and performance requirements to vendors on a continuing basis. Vendors should ensure that system upgrades, service packs, and bug fixes are made available to grid operators in a timely manner.**

**Actions Taken:** On May 2, 2006, the NERC Board of Trustees voted to accept Critical Infrastructure Protection (CIP)-002 through CIP-009 standards. These standards became effective June 1, 2006, at which time the Urgent Action 1200 standard was superseded. As of May 25, 2006, the CIP-002 through CIP-009 standards have not been submitted by NERC to FERC for approval as reliability standards. When the subject standards are submitted, FERC will start the process of public comment and determine whether the standards should be accepted and approved.

**Action Required to Fully Implement Recommendation 33:** R.33 will be implemented as part of the development of a permanent Cyber Security Standard. (See R32.A)

**R34. Develop corporate-level IT security governance and strategies.**

**Control areas and reliability coordinators and other grid-related organizations should have a planned and documented security strategy, governance model, and architecture for EMS automation systems.**

**Actions Taken:** The NERC Urgent Action Cyber Security Standard has been in place since August 2003 and includes requirements for corporate security strategy and governance.

**Action Required to Fully Implement Recommendation 34:** Full and continuing implementation is underway in this area. This reflects increased focus on IT systems that are involved in the control and monitoring of electric systems and their components through NERC. NERC CIPC has worked to continuously improve and promote physical and cyber security measures. NERC has developed permanent Cyber Security Standards to address requirements for corporate security strategy and governance. (See Actions Required for Recommendations 32.A and 32.B.)

**R35. Implement controls to manage system health, network monitoring, and incident management.**

**IT and EMS support personnel should implement technical controls to detect, respond to, and recover from system and network problems. Grid operators, dispatchers, and IT and EMS support personnel should be provided the tools and training to ensure the health of IT systems is monitored and maintained.**

**Actions Taken:** The NERC CIPC will support the NERC Operating Committee as Recommendation 35 primarily deals with operations and the health of the IT network. It has been determined that on August 14, 2003, both grid operators and IT support personnel did not have the situational awareness of the health of the IT systems that provided grid information both globally and locally. NERC has developed permanent Cyber Security Standards to address requirements for corporate security strategy and governance. On May 2, 2006, the NERC Board of Trustees voted to accept Critical Infrastructure Protection (CIP)-002 through CIP-009 standards. These standards became effective June 1, 2006, at which time the Urgent Action 1200 standard was superseded. As of May 25, 2006, the CIP-002 through CIP-009 standards have not been submitted by NERC to FERC for approval as reliability standards. When the subject standards are submitted, FERC will start the process of public comment and determine whether the standards should be accepted and approved.

**Action Required to Fully Implement Recommendation 35:** See the discussion of R32.A for actions required to establish a permanent Cyber Security Standard as it also applies to the implementation of R35.

**R36. Initiate a U.S.-Canada risk management study**

**In cooperation with the electricity sector, federal governments should strengthen and expand the scope of the existing risk management initiatives by undertaking a bilateral (Canada-United States) study of the vulnerabilities of shared electricity infrastructure and cross-border interdependencies. Common threat and vulnerability assessment methodologies should be also developed, based on the work undertaken in the pilot phase of the current joint Canada-U.S. vulnerability assessment initiative, and their use promoted by control areas and reliability coordinators. To coincide with these initiatives, the electricity sector, in association with federal governments, should develop policies and best practices for effective risk management and risk mitigation.**[74]

**Actions Taken:**

- DOE in cooperation with DHS is working with NRCan to plan for future vulnerability assessments of shared electricity infrastructure and cross-border interdependencies. NRCan-DOE and the Public Safety and Emergency Preparedness Canada (PSEPC)-DHS are developing screening criteria, to be discussed with industry, to determine which assets/facilities are critical and will develop a plan for working with the private sector facility owners—generation, transmission, dams—provincial/state authorities, and key electricity sector stakeholders to systematically assess the vulnerabilities of the selected assets/facilities.

- NERC CIPC, in cooperation with DOE, DHS, PSEPC, and NRCan has developed guidance on security risk assessment methodologies. This includes background information, information on the basic components of security risk assessments, tips on how to set up a risk assessment framework, and information on several risk assessment methods that may be adopted or adapted for use as part of an organization's risk assessment program. The final document, *Risk-Assessment Methodologies for Use in the Electric Utility Industry* is complete.

- DOE analyzed and developed a report summarizing the characteristics of various *off-the-shelf* risk and vulnerability assessment methodologies, taking into account the physical and cyber security that is applicable to the energy sector.

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[74] Although the recommendation stated the identification of cross-border interdependencies, the key participants in the recommendation implementation team agreed that this is not a cross-border issue. It is not necessarily the assets crossing a border that are critical to the reliability and security of the grid. Rather, critical nodes, regardless of their distance from the border, which could negatively impact the grid, must be identified.

- NRCan, in collaboration with PSEPC, DHS, DOE and NERC, will develop generic lessons learned resulting from the vulnerability assessments carried out in 2004 under Action Item 21 of the Canada-U.S. Smart Border Agreement.

- NERC, in cooperation with DOE, DHS, and PSEPC, continues to develop security guidelines to enhance risk management within the electric infrastructure.

- NERC CIPC has developed a *Time-Stamping Guideline* and made it available to the NERC Planning Committee. Guidelines have been developed for the following:

    1. Physical Security – Substations
    2. Patch Management for Control Systems
    3. Control System – Business Network Electronic Connectivity

- NERC, DHS and PSEPC, share information through industry reports of incidents and vulnerabilities as well as DHS and PSEPC reports on threats, including periodic DHS sponsored cleared intelligence briefings. In response, NERC continues to propose mitigation measures through cyber, physical, and personnel security processes in accordance with the changing threat environment.

- NERC, the Canadian Electricity Association (CEA), DOE, DHS, PSEPC, and NRCan are participating in the International Electricity Infrastructure Assurance (IEIA) Forum, which also includes the United States, Canada, Australia, Great Britain and New Zealand. The purpose of this forum is to leverage the expertise of others in the areas of policies, good practices, technology, research and development, and incident analysis to help identify and address the vulnerabilities of electricity infrastructures and their interdependencies.

**Action Required to Fully Implement Recommendation 36:** This recommendation calls for a bilateral study of the vulnerabilities of shared electricity infrastructure and cross-border interdependencies. The work that was done by a joint Canada - U.S. team as a pilot project was the first phase of this study. In 2004, this team conducted a vulnerability assessment of critical cross-border electrical generation facilities, transmission lines and dams with the private sector electricity facility owners. The work was undertaken pursuant to the commitments made by both countries under the Smart Border Declaration in December, 2001. Assessments of remaining critical cross-border electricity sector facilities were conducted in 2005-2006 and others are planned for 2006-07 as the next phase of this study. In collaboration with governments, NERC CIPC and the ERO—will keep abreast of the changing threat environment, which in isolation or in sequence would affect (pose a threat to) the reliability of the shared electric infrastructure and, propose risk management alternatives through cyber, physical and personnel security processes. Threat information will be shared through industry reports of threats and incidents and DHS/PSEPC-sponsored intelligence briefings.

This is a critical infrastructure security issue and NRCan and DOE, in consultation with other key stakeholders will also continue to monitor the situation and industry implementation of the new standards. This is in keeping with their ongoing responsibilities for the protection of critical cross-border energy infrastructure.

**R37. Improve IT forensic and diagnostic capabilities.**

**Control areas and reliability coordinators should seek to improve internal forensic and diagnostic capabilities, ensure that IT support personnel who support EMS automation systems are familiar with the systems' design and implementation, and make certain that IT support personnel who support EMS automation systems are trained in using appropriate tools for diagnostic and forensic analysis and remediation.**

**Actions Taken:** NERC CIPC discusses experience-based case studies in their regular meetings including reporting, analysis and conclusions of real security incidents: Topics have included:

- Best practices for seizing electronic and physical evidence
- Substation security; and
- Case studies of actual security incidents – detection, response, threat assessment.

NERC will ensure that CIPC members disseminate appropriate information to industry stakeholders.

**Action Required to Fully Implement Recommendation 37:** NERC has been the lead agency for fully implementing Recommendation 37. In response to new challenges and the availability of new technologies, activity in this area will be ongoing for the ERO. The ERO will assume a monitoring and reporting role with respect to the implementation of the recommendations.

**R38. Assess IT risk and vulnerability at scheduled intervals**

**IT and EMS support personnel should perform regular risk and vulnerability assessment activities for automation systems (including EMS applications and underlying operating systems) to identify weaknesses, high-risk areas, and mitigating actions such as improvements in policy, procedure, and technology.**

**Actions Taken:** The NERC Urgent Action Cyber Security Standard has been in place since August 2003 and includes requirements for periodically assessing risks and vulnerabilities. NERC is developing permanent Cyber Security Standards to address requirements for periodically assessing risks and vulnerabilities. NERC, in cooperation with DOE, DHS, and PSEPC, has developed a number of security guidelines related to the security, safety and reliability of Process Control Systems (PCS) and SCADA including:

- Cyber Security – Risk Management;
- Cyber Security – Access Controls;
- Cyber Security – Intrusion Detection;
- Cyber Security – IT Firewalls;
- Securing Remote Access to Electronic Control and Protection Systems;
- Patch Management for Control Systems; and
- Control System – Business Network Electronic Connectivity.

NERC CIPC is working with the DHS-sponsored PCS forum with several other critical infrastructure sectors, government, vendors, and standards bodies to assist in accelerating the development of technology that will enhance the security, safety, and reliability of PCS and SCADA systems.

**Action Required to Fully Implement Recommendation R38:** Development of new security guidelines to help protect the electricity infrastructure has been an ongoing area of activity for NERC CIPC and will be an ongoing area of activity for the ERO. NERC CIPC and the new ERO will continue outreach programs to raise and maintain awareness of cyber security issues. They will also provide support to the NERC Operating Committee groups with the implementation of mandatory operating standards, advisory planning standards, and guidelines. The ERO will assume a monitoring and reporting role in the implementation of the recommendations. On May 2, 2006, the NERC Board of Trustees voted to accept CIP-002 through CIP-009 standards. These standards will become effective June 1, 2006, at which time the Urgent Action 1200 standard will be superseded. As of May 25, 2006, the CIP-002 through CIP-009 standards have not been submitted by NERC to FERC for approval as reliability standards. When the subject standards are submitted, FERC will start the process of public comment and determine whether the standards should be accepted and approved.

**R39. Develop capability to detect wireless and remote wireline intrusion and surveillance.**

**Both the private and public sector should promote the development of the capability for all control areas and reliability coordinators to reasonably detect intrusion and surveillance of wireless and remote wireline access points and transmissions. Control areas and reliability coordinators should also conduct periodic reviews to ensure that their user base is in compliance with existing wireless and remote wireline access rules and policies.**

**Action Taken:** NERC has developed a security guideline on Cyber Security – Intrusion Detection. *The NERC Permanent Cyber Security Standards* includes requirements for monitoring and controlling access. *The NERC Urgent Action Cyber Security Standard* has been in place since August 2003 and it includes requirements for monitoring and controlling access. On May 2, 2006, the NERC Board of Trustees voted to accept CIP-002 through CIP-009 standards. These standards will become effective June 1, 2006, at which time the Urgent Action 1200 standard will be superseded. As of May 25, 2006, the CIP-002 through CIP-009 standards have not been submitted by NERC to FERC for approval as reliability standards. When the subject standards are submitted, FERC will start the process of public comment and determine whether the standards should be accepted and approved.

DHS, in cooperation with NERC and the industry, is conducting an Intrusion Detection System pilot project. DHS will share the generic lessons-learned with the industry.

DOE, DHS, PSEPC, and NRCan, worked with the private sector to develop a *Roadmap to Secure Control Systems in the Energy Sector*. The purpose of the *Roadmap* is to identify risks and industry needs in order to better secure control systems. It is intended to coordinate federal government, industry, academia, vendors and national labs, enhance collaboration, and better allocate resources for all stakeholders. The *Roadmap* document was released in February 2006.

Control systems are the nerve system of the electric power infrastructure and the security and proper operation of today's control systems are highly dependent on telecommunications systems (wire and wireless). Hence, the telecommunications sector was invited to participate in developing the *Roadmap*. The telecommunications and electricity sectors are engaged also via the Telecommunications Electric Power Interdependencies Task Force.

NERC, and the new ERO, in cooperation with DOE, DHS, and PSEPC, will continue to exchange information and collaborate with the vendor community in identifying and addressing security issues related to the electric infrastructure.

**Actions Required to Fully Implement Recommendation 39:** No further action is needed to implement this recommendation. However, substantial ongoing effort is required to address security and respond to any new challenges.

**R40. Control access to operationally sensitive equipment.**

**Reliability Coordinators and Control Areas should implement stringent policies and procedures to control access to sensitive equipment and/or work areas.**

**Actions Taken:** NERC in cooperation with DOE, DHS, and PSEPC, developed the guideline, *Physical Security – Substations,* to address access issues and a new security guideline, *Control System – Business Network Electronic Connectivity*, which addresses access to sensitive equipment and work areas. CIPC members are actively supporting the development of the NERC permanent standard which also addresses access issues. NERC, in cooperation with DOE, DHS, and PSEPC, will continue to develop new security guidelines, enhance existing security guidelines, and provide education in relation to these guidelines.

**Action Required to Fully Implement Recommendation 40:** No further action is needed to implement this recommendation.

**R41. NERC should provide guidance on employee background checks.**

**NERC should provide guidance on the implementation of its recommended standards on background checks, and control areas and reliability coordinators should review their policies regarding background checks to ensure they are adequate.**

**Actions Taken:** The NERC Urgent Action Cyber Security Standard has been in place since August 2003 and includes requirements for employee background screening. NERC is developing permanent Cyber Security Standards to address requirements for employee background screening, and includes references to good industry practices. On May 2, 2006, the NERC Board of Trustees voted to accept CIP-002 through CIP-009 standards. These standards became effective June 1, 2006, at which time the Urgent Action 1200 standard was superseded. As of May 25, 2006, the CIP-002 through CIP-009 standards have not been submitted by NERC to FERC for approval as reliability standards. When the subject standards are submitted, FERC will start the process of public comment and determine whether the standards should be accepted and approved.

**Actions Required to Fully Implement Recommendation 41**: No further actions will be required to implement this recommendation.

**R42. Confirm NERC ES-ISAC as the central point for sharing security information and analysis.**

**The NERC ES-ISAC should be confirmed as the central electricity sector point of contact for security incident reporting and analysis. Policies and protocols for cyber and physical incident reporting should be further developed including a mechanism for monitoring compliance. There also should be uniform standards for the reporting and sharing of physical and cyber security incident information across both the private and public sectors.**

**Actions Taken:** The NERC CIPC Executive Committee has governance responsibility for the NERC-operated Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The NERC CIPC Executive Committee has become the Electricity Sector Coordinating Council for providing advice to DHS and other federal government agencies on critical infrastructure protection and other issues. The CIPC Executive Committee includes a Canadian representative. In consultation with the other NERC Committees, CIPC is seeking opportunities to increase Canadian participation. The ES-

ISAC has a Standard Operating Procedure and guidelines in place for reporting physical and cyber security threats and incidents to internal corporate security, private sector-specific information sharing and analysis bodies (including other sector ISACs), law enforcement, and government agencies. NERC, DOE, DHS, and PSEPC are currently reviewing and updating the Standard Operating Procedure.

A Standard Operating Procedure for reporting suspected or real security incidents is in place, along with standard CIP-001-1 which requires entities to report sabotage incidents.

DHS and NERC CIPC are developing a new Internet-based communications backbone—Homeland Security Information Network - Electric Sector or HSIN-ES. This network will allow the industry to communicate within the industry, with other industry sectors, and with government agencies in a secure fashion. HSIN-ES will provide enhanced reporting and information sharing.

Presently, PSEPC and DHS exchange information via the HSIN-ES. PSEPC and CEA exchange information on a regular basis via voice and electronic mechanisms. PSEPC and NERC exchange information via the ES-ISAC. Also, DHS and PSEPC have an Action Plan in place to formalize the necessary mechanisms that would facilitate the sharing of electricity sector threat and vulnerability information between the Canadian and U.S. governments. DHS is working with the ES-ISAC to develop procedures under the DHS Protected Critical Infrastructure Information (PCII) program that will enable the secure sharing of sensitive security information with DHS and other U.S. departments. These procedures will provide guidance to the industry on submitting PCII information to DHS.

PSEPC has included provisions for the protection of commercially sensitive critical infrastructure information (CII) that is shared between the Government of Canada and the private sector in its proposed new legislation entitled the *Emergency Management Act*. The Bill received first reading in the Canadian House of Commons on May 8, 2006. PSEPC is reviewing other possible mechanisms for promoting a standardized, cohesive approach to protecting third party critical infrastructure information being shared with the Government of Canada while also exploring best practices with the provinces/territories that would encourage more sharing of critical infrastructure information.

Development and implementation of a common approach to critical infrastructure protection, which includes information sharing mechanisms, is also part of the Security and Prosperity Partnership between Canada, United States and Mexico.

**Actions Required to Fully Implement Recommendation 42:** The goals of this recommendation have been addressed and no further action is needed.

**R43. Establish clear authority for physical and cyber security.**

**The task force recommends that corporations establish clear authority and ownership for physical and cyber security. This authority should have the ability to influence corporate decision-making and the authority to make physical and cyber security-related decisions.**

**Actions Taken:** The NERC Urgent Action Cyber Security Standard has been in place since August 2003 and includes requirements for clear accountability for cyber and physical security. NERC is developing permanent Cyber Security Standards to address requirements for clear accountability for cyber and physical security. It is expected that the compliance with new standards will begin in 2006. On May 2, 2006, the NERC Board of Trustees voted to accept CIP-002 through CIP-009 standards. These standards became effective June 1, 2006, at which time the Urgent Action 1200 standard was superseded. As of May 25, 2006, the CIP-002 through CIP-009 standards have not been submitted by NERC to FERC for approval as reliability standards. When the subject standards are submitted, FERC will start the process of public comment and determine whether the standards should be accepted and approved.

NERC CIPC is collaborating with DOE in the development of a framework for conducting investigations that have security implications, including law enforcement, security-sensitive information and intelligence considerations.

**Action Required to Fully Implement Recommendation 43:** No further action will be required to implement this recommendation.

**R44. Develop procedures to prevent or mitigate inappropriate disclosure of information.**

**The private and public sectors should jointly develop and implement security procedures and awareness training in order to mitigate or prevent disclosure of information by the practices open source collection, elicitation and surveillance.**

**Actions Taken:** NERC CIPC developed a security guideline, *Protecting Potentially Sensitive Information*. NERC is developing permanent Cyber Security Standards to address requirements for data and information classification according to confidentiality. On May 2, 2006, the NERC Board of Trustees voted to accept CIP-002 through CIP-009 standards. These standards will become effective June 1, 2006, at which time the Urgent Action 1200 standard will be superseded. As of May 25, 2006, the CIP-002 through CIP-009 standards have not been submitted by NERC to FERC for approval as reliability standards. When the subject standards are submitted, FERC will start the process of public comment and determine whether the standards should be accepted and approved.

DHS is working with the ES-ISAC to develop procedures under the DHS PCII program that will enable the secure sharing of sensitive security information with DHS and other U.S. departments. These procedures will provide guidance to the industry on submitting PCII information to DHS. This issue is also under review by Canadian authorities. The challenges posed here must be identified and highlighted to the public sector so that they can be taken into consideration in the development and advancement of public policy.

**Actions Required to Fully Implement Recommendation 44:** The permanent Cyber Security Standard will include requirements that data and information be classified, if required. Industry continues to be concerned about government's need to obtain sensitive information from them and its ability to secure such information. This is being addressed through a DHS led process of developing a National Infrastructure Protection Plan mandated by the Homeland Security Presidential Directive 7. Efforts are underway in DHS to address security issues through the PCII program.

Ongoing implementation of R44 will be accomplished as part of the implementation of the permanent Cyber Security Standard.

## Group IV: Canadian Nuclear Power Sector
*(Recommendations 45, 46)*

**TABLE 3.4: Summary of Implementation Status of Recommendations 45 and 46**

| Recommendation Number | Fully Implemented | | Not Yet Fully Implemented | Entity Responsible for Full Implementation |
|---|---|---|---|---|
| | One-Time Action | Ongoing Activity | | |
| R45 | x | | | |
| R46 | x | | | |
| **Totals** | **2** | | | |

**R45. The Task Force recommends that the Canadian Nuclear Safety Commission request Ontario Power Generation and Bruce Power to review operating procedures and operator training associated with the use of adjuster rods.**

In Canada, it is the responsibility of those applying for licences to demonstrate that their facilities are safe to operate. A loss of bulk electricity supply (LOBES) is one of the events that must be considered when developing the safety case. Any changes allowing for alternative approaches to placing a reactor in an automatic mode through the use of adjuster rods must be carefully analyzed and considered in the context of the safety case for the reactor.

**Actions Taken:** Ontario Power Generation has reported on the use of adjuster rods at Darlington Nuclear Generating Station as part of its follow-up activities related to the LOBES event of August 2003. Changes to the control room operating procedures and simulator training program have been made. The Reactor Operator now performs the system checks and informs the Shift Manager or Control Room Shift Supervisor before placing the adjuster rods in automatic mode. Currently, there is no requirement for an independent check by either the Shift Manager or the Control Room Shift Supervisor. In summary, the issue regarding the use of the adjuster rods at Darlington has been addressed by Ontario Power Generation and is now closed.

Bruce Power Inc. has also reviewed its operating manuals, procedures, and associated training materials related to the use of adjuster rods and found them to be acceptable. No changes have therefore been recommended.

**Action Required to Fully Implement Recommendation 45:** No further action is required. The Canadian Nuclear Safety Commission (CNSC) considers this action item to be closed.

**R46. The Task Force recommends that the Canadian Nuclear Safety Commission purchase and install backup generation equipment.**

Such equipment is needed at CNSC for use in emergency situations.

**Actions Taken:** This capacity was installed at CNSC and became operational in August 2004.

**Action Required to Fully Implement Recommendation 46:** No further action is needed. The CNSC considers this action item to be closed.

# 4. CONCLUSIONS

*[To be written following the June 22, 2006, Conference for Public Review.]*