Appendix A

Members of the U.S.-Canada Power System Outage Task Force and Its Three Working Groups

Task Force Co-Chairs

Spencer Abraham, Secretary of the U.S. Department of Energy (USDOE)

R. John Efford, Canadian Minister of Natural Resources (current) and **Herb Dhaliwal** (August-December 2003)

Canadian Task Force Members

Linda J. Keen, President and CEO of the Canadian Nuclear Safety Commission

Anne McLellan, Deputy Prime Minister and Minister of Public Safety and Emergency Preparedness

John Manley, (previous) Deputy Prime Minister and Minister of Finance

Kenneth Vollman, Chairman of the National Energy Board

U.S. Task Force Members

Nils J. Diaz, Chairman of the Nuclear Regulatory Commission

Tom Ridge, Secretary of the U.S. Department of Homeland Security (DHS)

Pat Wood, III, Chairman of the Federal Energy Regulatory Commission (FERC)

Principals Managing the Working Groups

Jimmy Glotfelty, Director, Office of Electric Transmission and Distribution, USDOE

Dr. Nawal Kamel, Special Advisor to the Deputy Minister of Natural Resources Canada (NRCan)

Working Groups

Electric System Working Group

Co-Chairs

David Meyer, Senior Advisor, Office of Electric Transmission and Distribution, USDOE (U.S. Government)

Thomas Rusnov, Senior Advisor, Natural Resources Canada (Government of Canada)

Alison Silverstein, Senior Energy Policy Advisor to the Chairman, FERC (U.S. Government)

Canadian Members

David Barrie, Senior Vice President, Asset Management, Hydro One

David Burpee, Director, Renewable and Electrical Energy Division, NRCan (Government of Canada)

David McFadden, Chair, National Energy and Infrastructure Industry Group, Gowling, Lafleur, Henderson LLP (Ontario)

U.S. Members

Donald Downes, Public Utility Commission Chairman (Connecticut)

Joseph H. Eto, Staff Scientist, Ernest Orlando Lawrence Berkeley National Laboratory, Consortium for Electric Reliability Technology Solutions (CERTS)

Jeanne M. Fox, President, New Jersey Board of Pubic Utilities (New Jersey)

H. Kenneth Haase, Sr. Vice President, Transmission, New York Power Authority (New York)

J. Peter Lark, Chairman, Public Service Commission (Michigan)

Blaine Loper, Senior Engineer, Pennsylvania Public Utility Commission (Pennsylvania)

William McCarty, Chairman, Indiana Utility Regulatory Commission (Indiana)

David O'Brien, Vermont Public Service Department, Commissioner (Vermont)

David O'Connor, Commissioner, Division of Energy Resources, Office of Consumer Affairs and Business Regulation (Massachusetts)

Alan Schriber, Public Utility Commission Chairman (Ohio)

Gene Whitney, Policy Analyst, Office of Science and Technology Policy (U.S. Government)

Security Working Group

Co-Chairs

William J.S. Elliott, Assistant Secretary to the Cabinet, Security and Intelligence, Privy Council Office (Government of Canada)

Robert Liscouski, Assistant Secretary for Infrastructure, Department of Homeland Security (U.S. Government)

Canadian Members

Curt Allen, Director Corporate Security, Management Board Secretariat, Office of the Corporate Chief Information Officer, Government of Ontario

Gary Anderson, Chief, Counter-Intelligence-Global, Canadian Security Intelligence Service (Government of Canada)

Michael Devancy, Deputy Chief, Information Technology Security, Communications Security Establishment (Government of Canada)

James Harlick, Assistant Deputy Minister, Public Safety and Emergency Preparedness Canada (Government of Canada)

Peter MacAulay, Officer in Charge of Technological Crime Branch, Royal Canadian Mounted Police (Government of Canada)

Ralph Mahar, Chief, Technical Operations, Scientific and Technical Services, Canadian Security Intelligence Service (Government of Canada)

Dr. James Young, Commissioner of Public Security, Ontario Ministry of Public Safety and Security (Ontario)

U.S. Members

Sid Casperson, Director, Office of Counter Terrorism (New Jersey)

Vincent DeRosa, Deputy Commissioner, Director of Homeland Security, Department of Public Safety (Connecticut)

Harold M. Hendershot, Acting Section Chief, Computer Intrusion Section, Federal Bureau of Investigation (U.S. Government)

Kevin Kolevar, Chief of Staff to the Deputy Secretary of Energy, Department of Energy (U.S. Government)

Paul Kurtz, Special Assistant to the President and Senior Director for Critical Infrastructure Protection, Homeland Security Council (U.S. Government)

James McMahon, Senior Advisor (New York)

Colonel Michael C. McDaniel, Assistant Adjutant General for Homeland Security (Michigan)

John Overly, Executive Director, Division of Homeland Security (Ohio)

Andy Purdy, Deputy Director, National Cyber Security Division, Information Analysis and Infrastructure Protection Directorate, DHS

Kerry L. Sleeper, Commissioner, Public Safety (Vermont)

Arthur Stephens, Deputy Secretary for Information Technology, Office of Administration (Pennsylvania)

Steve Schmidt, Section Chief, Special Technologies and Applications, FBI

Richard Swensen, Under Secretary, Office of Public Safety and Homeland Security (Massachusetts)

Simon Szykman, Senior Policy Analyst, Office of Science and Technology Policy (U.S. Government)

Nuclear Working Group

Co-Chairs

Nils Diaz, Chairman, Nuclear Regulatory Commission (U.S. Government)

Linda J. Keen, President and Chief Executive Officer, Canadian Nuclear Safety Commission (Government of Canada)

Canadian Members

James Blyth, Director General, Directorate of Power Regulation, Canadian Nuclear Safety Commission (Government of Canada)

Duncan Hawthorne, Chief Executive Officer, Bruce Power (Ontario)

Robert Morrison, Senior Advisor to the Deputy Minister, Natural Resources Canada (Government of Canada)

Ken Pereira, Vice President, Operations Branch, Canadian Nuclear Safety Commission (Government of Canada)

U.S. Members

David J. Allard, CHP, Director, Bureau of Radiation Protection Department of Environmental Protection (Pennsylvania)

Frederick F. Butler, Commissioner, New Jersey Board of Public Utilities (New Jersey)

Sam J. Collins, Deputy Executive Director for Reactor Programs, Nuclear Regulatory Commission

Paul Eddy, Power Systems Operations Specialist, Public Service Commission (New York)

J. Peter Lark, Chairman, Public Service Commission (Michigan)

William D. Magwood IV, Director, Office of Nuclear Energy, Science and Technology, Department of Energy (U.S. Government)

Dr. G. Ivan Moldonado, Associate Professor, Mechanical, Industrial and Nuclear Engineering; University of Cincinnati (Ohio)

David O'Brien, Commissioner, Department of Public Service (Vermont)

David O'Connor, Commissioner, Division of Energy Resources, Office of Consumer Affairs and Business Regulation (Massachusetts)

Gene Whitney, Policy Analyst, National Science and Technology Policy, Executive Office of the President (U.S. Government)

Edward Wilds, Bureau of Air Management, Department of Environmental Protection (Connecticut)

This report reflects tireless efforts by hundreds of individuals not identified by name above. They include electrical engineers, information technology experts, and other specialists from across the North American electricity industry, the academic world, regulatory agencies in the U.S. and Canada, the U.S. Department of Energy and its national laboratories, the U.S. Department of Homeland Security, the U.S. Federal Bureau of Investigation, Natural Resources Canada, the Royal Canadian Mounted Police, the Bonneville Power Administration, the Western Area Power Administration, the Tennessee Valley Authority, the North American Electric Reliability Council, PJM Interconnection, Inc., Ontario's Independent Market Operator, and many other organizations. The members of the U.S.-Canada Power System Outage Task Force thank these individuals, and congratulate them for their dedication and professionalism.

Appendix B

Description of Outage Investigation and Process for Development of Recommendations

On August 14, 2003, the northeastern U.S. and Ontario, Canada, suffered one of the largest power blackouts in the history of North America. The area affected extended from New York, Massachusetts, and New Jersey west to Michigan, and from Ohio north to Ontario, Canada.

President George W. Bush and Prime Minister Jean Chrétien created a U.S.-Canada Task Force to identify the causes of the power outage and to develop recommendations to prevent and contain future outages. U.S. Energy Secretary Spencer Abraham and Minister of Natural Resources Canada Herb Dhaliwal, meeting in Detroit, Michigan, on August 20, agreed on an outline for the activities of the Task Force.

This appendix outlines the process used for the determination of why the blackout occurred and was not contained and explains how recommendations were developed to prevent and minimize the scope of future outages. Phase I of the process was completed when the Interim Report, identifying what happened and why, was released on November 19, 2003. This Final Report, released on April 5, 2004, completes Phase II of the process by providing recommendations acceptable to both countries for preventing and reducing the scope of future blackouts. This report, which encompasses both the findings of the Interim Report and updated information from continued analysis by the investigative teams, totally supersedes the Interim Report.

During Phase II, the Task Force sought the views of the public and expert stakeholders in Canada and the U.S. towards the development of the final recommendations. People were asked to comment on the Interim Report and provide their views on recommendations to enhance the reliability of the electric system in each country. The Task Force collected this information by several methods, including public forums, workshops of technical experts, and electronic submissions to the NRCan and DOE web sites.

Verbatim transcripts of the forums and workshops were provided on-line, on both the NRCan and DOE web sites. In Canada, which operates in both English and French, comments were posted in the language in which they were submitted. Individuals who either commented on the Interim Report, provided suggestions for recommendations to improve reliability, or both are listed in Appendix C. Their input was greatly appreciated. Their comments can be viewed in full or in summary at http://www.nrcan.gc.ca or at http://www.electricity.doe.gov.

Task Force Composition and Responsibilities

The co-chairs of the Task Force were U.S. Secretary of Energy Spencer Abraham and Minister of Natural Resources Canada (NRCan) Herb Dhaliwal for Phase I and Minister of NRCan R. John Efford for Phase II. Other U.S. members were Nils J. Diaz, Chairman of the Nuclear Regulatory Commission, Tom Ridge, Secretary of Homeland Security, and Pat Wood III, Chairman of the Federal Energy Regulatory Commission. The other Canadian members were Deputy Prime Minister John Manley during Phase I and Anne McLellan, Deputy Prime Minister and Minister of Public Safety and Emergency Preparedness during Phase II, Linda J. Keen, President and CEO of the Canadian Nuclear Safety Commission, and Kenneth Vollman, Chairman of the National Energy Board. The coordinators for the Task Force were Jimmy Glotfelty on behalf of the U.S. Department of Energy and Dr. Nawal Kamel on behalf of Natural Resources Canada.

On August 27, 2003, Secretary Abraham and Minister Dhaliwal announced the formation of three Working Groups to support the work of the Task Force. The three Working Groups addressed electric system issues, security matters, and questions related to the performance of nuclear power plants over the course of the outage. The members of the Working Groups were officials from relevant federal departments and agencies, technical experts, and senior representatives from the affected states and the Province of Ontario.

U.S.-Canada-NERC Investigation Team

Under the oversight of the Task Force, three investigative teams of electric system, nuclear and cyber and security experts were established to investigate the causes of the outage. The electric system investigative team was comprised of individuals from several U.S. federal agencies, the U.S. Department of Energy's national laboratories, Canadian electric industry, Canada's National Energy Board, staff from the North American Electric Reliability Council (NERC), and the U.S. electricity industry. The overall investigative team was divided into several analytic groups with specific responsibilities, including data management, determining the sequence of outage events, system modeling, evaluation of operating tools and communications, transmission system performance, generator performance, NERC and regulatory standards/procedures and compliance, system planning and design studies, vegetation and right-of-way management, transmission and reliability investments, and root cause analysis.

Additional teams of experts were established to address issues related to the performance of nuclear power plants affected by the outage, and physical and cyber security issues related to the bulk power infrastructure. The security and nuclear investigative teams also had liaisons who worked closely with the various electric system investigative teams mentioned above.

Function of the Working Groups

The U.S. and Canadian co-chairs of each of the three Working Groups (i.e., an Electric System Working Group, a Nuclear Working Group, and a Security Working Group) designed investigative assignments to be completed by the investigative teams. These findings were synthesized into a single Interim Report reflecting the conclusions of the three investigative teams and the Working Groups. For Phase II, the Interim Report was enhanced with new information gathered from the technical conferences, additional modeling and analysis and public comments. Determination of when the Interim and Final Reports were complete and appropriate for release to the public was the responsibility of the U.S.-Canada Task Force and the investigation co-chairs.

Confidentiality of Data and Information

Given the seriousness of the blackout and the importance of averting or minimizing future blackouts, it was essential that the Task Force's teams have access to pertinent records and data from the regional transmission operators (RTOs) and independent system operators (ISOs) and electric companies affected by the blackout, and data from the nuclear and security associated entities. The investigative teams also interviewed appropriate individuals to learn what they saw and knew at key points in the evolution of the outage, what actions they took, and with what purpose. In recognition of the sensitivity of this information, Working Group members and members of the teams signed agreements affirming that they would maintain the confidentiality of data and information provided to them, and refrain from independent or premature statements to the media or the public about the activities, findings, or conclusions of the individual Working Groups or the Task Force as a whole.

After publication of the Interim Report, the Task Force investigative teams continued to evaluate the data collected during Phase I. Continuing with Phase I criteria, confidentiality was maintained in Phase II, and all investigators and working group members were asked to refrain from independent or premature statements to the media or the public about the activities, findings, or conclusions of the individual Working Groups or the Task Force as a whole.

Relevant U.S. and Canadian Legal Framework

United States

The Secretary of Energy directed the Department of Energy (DOE) to gather information and conduct an investigation to examine the cause or causes of the August 14, 2003 blackout. In initiating this effort, the Secretary exercised his authority under section 11 of the Energy Supply and Environmental Coordination Act of 1974, and section 13 of the Federal Energy Administration Act of 1974, to gather energy-related information and conduct investigations. This authority gives him and the DOE the ability to collect such energy information as he deems necessary to assist in the formulation of energy policy, to conduct investigations at reasonable times and in a reasonable manner, and to conduct physical inspections at energy facilities and business premises. In addition, DOE can inventory and sample any stock of fuels or energy sources therein, inspect and copy records, reports, and documents from which energy information has been or is being compiled and to question such persons as it deems necessary. DOE worked closely with Natural Resources Canada and NERC on the investigation.

Canada

Minister Dhaliwal, as the Minister responsible for Natural Resources Canada, was appointed by Prime Minister Chrétien as the Canadian Co-Chair of the Task Force. Minister Dhaliwal worked closely with his American Co-Chair, Secretary of Energy Abraham, as well as NERC and his provincial counterparts in carrying out his responsibilities. When NRCan Minister R. John Efford assumed his role as the new Canadian Co-Chair, he continued to work closely with Secretary Abraham and the three Working Groups.

Under Canadian law, the Task Force was characterized as a non-statutory, advisory body that does not have independent legal personality. The Task Force did not have any power to compel evidence or witnesses, nor was it able to conduct searches or seizures. In Canada, the Task Force relied on voluntary disclosure for obtaining information pertinent to its work.

Oversight and Coordination

The Task Force's U.S. and Canadian coordinators held frequent conference calls to ensure that all components of the investigation were making timely progress. They briefed both Secretary Abraham and Minister R. John Efford (Minister Dhaliwal, Phase I) regularly and provided weekly summaries from all components on the progress of the investigation. During part of Phase I, the leadership of the electric system investigation team held daily conference calls to address analytical and process issues important to the investigation. The three Working Groups held weekly conference calls to enable the investigation teams to update the Working Group members on the state of the overall analysis. Conference calls also focused on the analysis updates and the need to ensure public availability of all inputs to the development of recommendations. Working Group members attended panels and face-to-face meetings to review drafts of the report.

Electric System Investigation Phase I Investigative Process

Collection of Data and Information from ISOs, Utilities, States, and the Province of Ontario

On Tuesday, August 19, 2003, investigators affiliated with the U.S. Department of Energy (DOE) began interviewing control room operators and other key officials at the ISOs and the companies most directly involved with the initial stages of the outage. In addition to the information gained in the interviews, the interviewers sought information and data about control room operations and practices, the organization's system status and conditions on August 14, the organization's operating procedures and guidelines, load limits on its system, emergency planning and procedures, system security analysis tools and procedures, and practices for voltage and frequency monitoring. Similar interviews were held later with staff at Ontario's Independent Electricity Market Operator (IMO) and Hydro One in Canada.

On August 22 and 26, NERC directed the reliability coordinators at the ISOs to obtain a wide range of data and information from the control area coordinators under their oversight. The data requested included System Control and Data Acquisition (SCADA) logs, Energy Management System (EMS) logs, alarm logs, data from local digital fault recorders, data on transmission line and generator "trips" (i.e., automatic disconnection to prevent physical damage to equipment), state estimator data, operator logs and transcripts, and information related to the operation of capacitors, phase shifting transformers, load shedding, static var compensators, special protection schemes or stability controls, and high-voltage direct current (HVDC) facilities. NERC issued another data request to FirstEnergy on September 15 for copies of studies since 1990 addressing voltage support, reactive power supply, static capacitor applications, voltage requirements, import or transfer capabilities (in relation to reactive capability or voltage levels), and system impacts associated with unavailability of the Davis-Besse plant. All parties were instructed that data and information provided to either DOE or NERC did not have to be submitted a second time to the other entity—all material provided would go into a common data base.

For the Interim Report the investigative team held three technical conferences (August 22, September 8-9, and October 1-3) with the RTOs and ISOs and key utilities aimed at clarifying the data received, filling remaining gaps in the data, and developing a shared understanding of the data's implications.

Data "Warehouse"

The data collected by the investigative team was organized in an electronic repository containing thousands of transcripts, graphs, generator and transmission data and reports at the NERC headquarters in Princeton, New Jersey. The warehouse contains more than 20 gigabytes of information, in more than 10,000 files. This established a set of validated databases that the analytic teams could access as needed.

Individual investigative teams conducted their activities through a number of in-person meetings as well as conference calls and e-mail communications over the months of the investigation. Detailed investigative team findings will be included in upcoming technical reports issued by NERC.

The following were the information sources for the Electric System Investigation:

- Interviews conducted by members of the U.S.-Canada Electric Power System Outage Investigation Team with personnel at all of the utilities, control areas and reliability coordinators in the weeks following the blackout.
- Three fact-gathering meetings conducted by the Investigation Team with personnel from the above organizations on August 22, September 8 and 9, and October 1 to 3, 2003.
- Three public hearings held in Cleveland, Ohio; New York City, New York; and Toronto, Ontario.
- Two technical conferences held in Philadelphia, Pennsylvania, and Toronto, Canada.
- Materials provided by the above organizations in response to one or more data requests from the Investigation Team.
- All taped phone transcripts between involved operations centers.
- Additional interviews and field visits with operating personnel on specific issues in October 2003 and January 2004.
- Field visits to examine transmission lines and vegetation at short-circuit locations.
- Materials provided by utilities and state regulators in response to data requests on vegetation management issues.
- Detailed examination of thousands of individual relay trips for transmission and generation events.

Data Exploration and Requirements

This group requested data from the following control areas and their immediate neighbors: MISO, MECS, FE, PJM, NYISO, ISO-NE, and IMO. The data and exploration and requirements group's objective was to identify industry procedures that are in place today for collecting information following large-scale transmission related power outages and to assess those procedures in terms of the August 14, 2003 power outage investigation.

They sought to:

- Determine what happened in terms of immediate causes, sequence of events, and resulting consequences;
- Understand the failure mechanism via recordings of system variables such as frequency, voltages, and flows;
- Enable disturbance re-creation using computer models for the purposes of understanding the mechanism of failure, identifying ways to avoid or mitigate future failures, and assessing and improving the integrity of computer models;
- Identify deeper, underlying factors contributing to the failure (e.g., general policies, standard practices, communication paths, organizational cultures).

Sequence of Events

More than 800 events occurred during the blackout of August 14. The events included the opening and closing of transmission lines and associated breakers and switches, the opening of transformers and associated breakers, and the tripping and starting of generators and associated breakers. Most of these events occurred in the few minutes of the blackout cascade between 16:06 and 16:12 EDT. To properly analyze a blackout of this magnitude, an accurate knowledge of the sequence of events must be obtained before any analysis of the blackout can be performed.

Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was variation from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized to the National Institute of Standards and Technology (NIST) standard clock in Boulder, CO. Validating the timing of specific events became a large, important, and sometimes difficult task. This work was also critical to the issuance by the Task Force on September 12 of a "timeline" for the outage. The timeline briefly described the principal events, in sequence, leading up to the initiation of the outage's cascade phase, and then in the cascade itself. The timeline was not intended, however, to address the causal relationships among the events described, or to assign fault or responsibility for the blackout. All times in the chronology are in Eastern Daylight Time.

System Modeling and Simulation Analysis

The system modeling and simulation team (SMST) replicated system conditions on August 14 and the events leading up to the blackout. The modeling reflects the state of the electric system. Once benchmarked to actual conditions at selected critical times on August 14, it allowed analysts to conduct a series of sensitivity studies to determine if the system was stable and within limits at each point in time leading up to the cascade. The analysis also confirmed when the system became unstable and allowed analysts to test whether measures such as load-shedding would have prevented the cascade.

This team consisted of a number of NERC staff and persons with expertise in areas necessary to read and interpret all of the data logs, digital fault recorder information, sequence of events recorders information, etc. The team consisted of about 40 people involved at various different times with additional experts from the affected areas to understand the data.

Overall, this team:

- Created steady-state power flow cases for observed August 14 system conditions starting at 15:00 EDT through about 16:05 EDT (when powerflow simulations were no longer adequate), about the time of the Sammis-Star 345-kV outage.
- Compiled relevant data for dynamic modeling of affected systems (e.g. generator dynamic models, load characteristics, special protection schemes, etc.).
- Performed rigorous contingency analysis (over 800 contingencies in Eastern Interconnection run) to determine if the system was within operating within thermal and voltage limits, and within limits for possible further contingencies (N-1 contingencies) prior to and during the initial events of the blackout sequence.
- Performed sensitivity analysis to determine the significance of pre-existing conditions such as transmission outages in Cinergy and Dayton, and the earlier loss of Eastlake unit 5 generation.
- Performed "what-if" analysis to determine potential impacts of remedial actions such as reclosing of outages facilities during the sequence of events, load shedding, generation redispatch, and combinations of load shedding and redispatch.
- Compared transaction tags for August 14, to show how they matched up with those of other days in 2003 and 2002.
- Analyzed the transactions and generation dispatch changes used to bring replacement power for the loss of Eastlake 5 generation into FirstEnergy, to determine where the replacement power came from.
- Analyzed the performance of the Interchange Distribution Calculator (IDC) and its potential capability to help mitigate the overloads.

The SMST began its efforts using the base case data and model provided by FirstEnergy as its foundation.

The modeling and system studies work was performed under the guidance of a specially formed MAAC-ECAR-NPCC (MEN) Coordinating Group, consisting of the Regional Managers from those three regions impacted by the blackout, and their respective regional chairmen or designees.

Assessment of Operations Tools, SCADA/EMS, Communications, and Operations Planning

The Operations Tools, SCADA/EMS, Communications, and Operations Planning Team assessed the observability of the electric system to operators and reliability coordinators, and the availability and effectiveness of operational (real-time and day-ahead) reliability assessment tools, including redundancy of views and the ability to observe the "big picture" regarding bulk electric system conditions. The team investigated operating practices and effectiveness of operating entities and reliability coordinators in the affected area. This team investigated all aspects of the blackout related to operator and reliability coordinator knowledge of system conditions, action or inactions, and communications.

The Operations and Tools team conducted extensive interviews with operating personnel at the affected facilities. They participated in the technical investigation meetings with affected operators in August, September and October and reviewed the August 14 control room transcripts in detail. This group investigated the performance of the MISO and FirstEnergy EMS hardware and software and its impact on the blackout, and looked at operator training (including the use of formal versus "on-the-job" training) and the communications and interactions between the operations and information technology support staff at both organizations.

Frequency/ACE Analysis

The Frequency/ACE Team analyzed potential frequency anomalies that may have occurred on August 14, as compared to typical interconnection operations. The team also determined whether there were any unusual issues with control performance and frequency and any effects they may have had related to the cascading failure, and whether frequency-related anomalies were contributing factors or symptoms of other problems leading to the cascade.

Assessment of Transmission System Performance, Protection, Control, Maintenance, and Damage

This team investigated the causes of all transmission facility automatic operations (trips and reclosings) leading up to and through to the end of the cascade on all facilities greater than 100 kV. Included in the review were relay protection and remedial action schemes, including under-frequency load-shedding and identification of the cause of each operation and any misoperations that may have occurred. The team also assessed transmission facility maintenance practices in the affected area as compared to good utility practice and identified any transmission equipment that was damaged as a result of the cascading outage. The team reported patterns and conclusions regarding what caused transmission facilities to trip; why did the cascade extend as far as it did and not further into other systems; any misoperations and the effect those misoperations had on the outage; and any transmission equipment damage. Also the team reported on the transmission facility maintenance practices of entities in the affected area compared to good utility practice.

Assessment of Generator Performance, Protection, Controls, Maintenance, and Damage

This team investigated the cause of generator trips for all generators with a 10 MW or greater nameplate rating leading to and through the end of the cascade. The review included the cause for the generator trips, relay targets, unit power runbacks, and voltage/reactive power excursions. The team reported any generator equipment that was damaged as a result of the cascading outage. The team reported on patterns and conclusions regarding what caused generation facilities to trip. The team identified any unexpected performance anomalies or unexplained events. The team assessed generator maintenance practices in the affected area as compared to good utility practice. The team analyzed the coordination of generator under-frequency settings with transmission settings, such as under-frequency load shedding. The team gathered and analyzed data on affected nuclear units and worked with the Nuclear Regulatory Commission to address U.S. nuclear unit issues.

The Generator Performance team sent out an extensive data request to generator owners during Phase I of the investigation, but did not receive the bulk of the responses until Phase II. The analysis in this report uses the time of generator trip as it was reported by the plant owner, or the time when the generator ceased feeding power into the grid as determined by a system monitoring device, and synchronized those times to other known grid events as best as possible. However, many generation owners offered little information on the cause of unit trips or key information on conditions at their units, so it may never be possible to fully determine what happened to all the generators affected by the blackout, and why they performed as they did. In particular, it is not clear what point in time each reported generator trip time reflects—i.e., when in the cycle between when the generator first detected the condition which caused it to trip, or several seconds later when it actually stopped feeding power into the grid. This lack of clear data hampered effective investigation of generator issues.

Vegetation Management

For Phase I the Vegetation/Right of Way Team conducted a field investigation into the contacts that occurred between trees and conductors on August 14 within the FirstEnergy, Dayton Power & Light and Cinergy service areas. The team also examined detailed information gained from data requests to these and other utilities, including historical outages from tree contacts on these lines. These findings were included in the Interim Report and detailed in an interim report on utility vegetation management, posted at http://www.ferc.gov/cust-protect/moi/uvm-initial-report.pdf.

The team also requested information from the public utility commissions in the blackout area on any state requirements for transmission vegetation management and right-of-way maintenance.

Beginning in Phase I and continuing into Phase II, the Vegetation/ROW team looked in detail at the vegetation management and ROW maintenance practices for the three utilities above, and compared them to accepted utility practices across North America. Issues examined included ROW legal clearance agreements with landowners, budgets, tree-trimming cycles, organization structure, and use of herbicides. Through CN Utility Consulting, the firm hired by FERC to support the blackout investigation, the Vegetation/ROW team also identified "best practices" for transmission ROW management. They used those practices to evaluate the performance of the three utilities involved in August 14 line outages and also to evaluate the effectiveness of utility vegetation management practices generally.

On March 2, 2004, FERC released CN Utility Consulting's "Utility Vegetation Management Final Report" (see http://www.ferc.gov/cust-protect/moi/uvm-final-report.pdf).

Root Cause Analysis

The investigation team used a technique called root cause analysis to help guide the overall investigation process in an effort to identify root causes and contributing factors leading to the start of the blackout in Ohio. The root cause analysis team worked closely with the technical investigation teams providing feedback and queries on additional information. Also, drawing on other data sources as needed, the root cause analysis verified facts regarding conditions and actions (or inactions) that contributed to the blackout.

Root cause analysis is a systematic approach to identifying and validating causal linkages among conditions, events, and actions (or inactions) leading up to a major event of interest—in this case the August 14 blackout. It has been successfully applied in investigations of events such as nuclear power plant incidents, airplane crashes, and the recent Columbia space shuttle disaster.

Root cause analysis is driven by facts and logic. Events and conditions that may have helped to cause the major event in question are described in factual terms, and causal linkages are established between the major event and earlier conditions or events. Such earlier conditions or events are examined in turn to determine their causes, and at each stage the investigators ask whether the particular condition or event could have developed or occurred if a proposed cause (or combination of causes) had not been present. If the particular event being considered could have occurred without the proposed cause (or combination of causes), the proposed cause or combination of causes is dropped from consideration and other possibilities are considered.

Root cause analysis typically identifies several or even many causes of complex events; each of the various branches of the analysis is pursued until either a "root cause" is found or a non-correctable condition is identified. (A condition might be considered as non-correctable due to existing law, fundamental policy, laws of physics, etc.). Sometimes a key event in a causal chain leading to the major event could have been prevented by timely action by one or another party; if such action was feasible, and if the party had a responsibility to take such action, the failure to do so becomes a root cause of the major event.

Phase II

On December 12, 2003, Paul Martin was elected as the new Prime Minister of Canada and assumed responsibility for the Canadian section of the Power System Outage Task Force. Prime Minister Martin appointed R. John Efford as the new Minister of Natural Resources Canada and co-chair of the Task Force.

Press releases, a U.S. Federal Register notice, and ads in the Canadian press notified the public and stakeholders of Task Force developments. All public statements were released to the media and are available on the OETD and the NRCan web sites.

Several of the investigative teams began their work during Phase I and completed it during Phase II. Other teams could not begin their investigation into the events related to the cascade and blackout, beginning at 16:05:57 EDT on August 14, 2003, until analysis of the Ohio events before that point was completed in Phase I.

System Planning, Design and Studies Team

The SPDST studied reactive power management, transactions scheduling, system studies and system operating limits for the Ohio and ECAR areas. In addition to the data in the investigation data warehouse, the team submitted six comprehensive data requests to six control areas and reliability coordinators, including FirstEnergy, to build the foundation for its analyses. The team examined reactive power and voltage management policies, practices and criteria and compared them to actual and modeled system conditions in the affected area and neighboring systems. They assessed the process of assessing and approving transaction schedules and tags and the coordination of those schedules and transactions in August, 2003, and looked at the impact of tagged transactions on key facilities on August 14. Similarly, the team examined system operating limits in effect for the affected area on August 14, how they had been determined, and whether they were appropriate to the grid as it existed in August 2003. They reviewed system studies conducted by FirstEnergy and ECAR for 2003 and prior years, including the methodologies and assumptions used in those studies and how those were coordinated across adjoining control areas and councils. The SPDST also compared how the studied conditions compared to actual conditions on August 14. For all these matters, the team compared the policies, studies and practices to good utility practices.

The SPDST worked closely with the Modeling and System Simulation Team. They used data provided by the control areas, RTOs and ISOs on actual system conditions across August 2003, and NERC Tag Dump and TagNet data. To do the voltage analyses, the team started with the MSST's base case data and model of the entire Eastern Interconnection, then used a more detailed model of the FE area provided by FirstEnergy. With these models they conducted extensive PV and VQ analyses for different load levels and contingency combinations in the Cleveland-Akron area, running over 10,000 different power flow simulations. Team members have extensive experience and expertise in long-term and operational planning and system modeling.

NERC Standards, Procedures and Compliance Team

The SP&C team was charged with reviewing the NERC Operating Policies and Planning Standards for any violations that occurred in the events leading up to and during the blackout, and assessing the sufficiency or deficiency of NERC and regional reliability standards, policies and procedures. They were also directed to develop and conduct audits to assess compliance with the NERC and regional reliability standards as relevant to the cause of the outage.

The team members, all experienced participants in the NERC compliance and auditing program, examined the findings of the Phase I investigation in detail, building particularly upon the root cause analysis. They looked independently into many issues, conducting additional interviews as needed. The team distinguished between those violations which could be clearly proven and those which were problematic but not fully provable. The SP&C team offered a number of conclusions and recommendations to improve operational reliability, NERC standards, the standards development process and the compliance program.

Dynamic Modeling of the Cascade

This work was conducted as an outgrowth of the work done by the System Modeling and Simulation team in Phase I, by a team composed of the NPCC System Studies-38 Working Group on Inter-Area Dynamic Analysis, augmented by representatives from ECAR, MISO, PJM and SERC. Starting with the steady-state power flows developed in Phase I, they moved the analysis forward across the Eastern Interconnection from 16:05:50 EDT on in a series of first steady-state, then dynamic simulations to understand how conditions changed across the grid.

This team is using the model to conduct a series of "what if" analyses, to better understand what conditions contributed to the cascade and what might have happened if events had played out differently. This work is described further within Chapter 6.

Additional Cascade Analysis

The core team for the cascade investigation drew upon the work of all the teams to understand the cascade after 16:05:57. The investigation's official Sequence of Events was modified and corrected as appropriate as additional information came in from asset owners, and as modeling and other investigation revealed inaccuracies in the initial data reports. The team issued additional data requests and looked closely at the data collected across the period of the cascade. The team organized the analysis by attempting to link the individual area and facility events to the power flows, voltages and frequency data recorded by Hydro One's PSDRs (as seen in Figures 6.16 and 6.25) and similar data sets collected elsewhere. This effort improved the team's understanding of the interrelationships between the interaction, timing and impacts of lines, loads and generation trips, which are now being confirmed by dynamic modeling. Graphing, mapping and other visualization tools also created insights into the cascade, as with the revelation of the role of zone 3 relays in accelerating the early spread of the cascade within Ohio and Michigan.

The team was aided in its work by the ability to learn from the studies and reports on the blackout completed by various groups outside the investigation, including those by the Public Utility Commission of Ohio, the Michigan Public Service Commission, the New York ISO, ECAR and the Public Service Commission of New York.

Beyond the work of the Electric System investigation, the Security and Nuclear investigation teams conducted additional analyses and updated their interim reports with the additional findings.

Preparation of Task Force Recommendations

Public and stakeholder input was an important component in the development of the Task Force's recommendations. The input received covered a wide range of subjects, including enforcement of reliability standards, improving communications, planning for responses to emergency conditions, and the need to evaluate market structures. See Appendix C for a list of contributors.

Three public forums and two technical conferences were held to receive public comments on the Interim Report and suggested recommendations for consideration by the Task Force. These events were advertised by various means, including announcements in the *Federal Register* and the *Canada Gazette*, advertisements in local newspapers in the U.S., invitations to industry through NERC, invitations to the affected state and provincial regulatory bodies, and government press releases. All written inputs received at these meetings and conferences were posted for additional comment on public websites maintained by the U.S. Department of Energy and Natural Resources Canada (www.electricity.doe.gov and www.nrcan.gc.ca, respectively). The transcripts from the meetings and conferences were also posted on these websites.

- Members of all three Working Groups participated in public forums in Cleveland, Ohio (December 4, 2003), New York City (December 5, 2003), and Toronto, Ontario (December 8, 2003).
- The ESWG held two technical conferences, in Philadelphia, Pennsylvania (December 16, 2003), and Toronto, Ontario (January 9, 2004).
- The NWG also held a public meeting on nuclear-related issues pertaining to the blackout at the U.S. Nuclear Regulatory Commission headquarters in Rockville, Maryland (January 6, 2004).

The electric system investigation team also developed an extensive set of technical findings based on team analyses and cross-team discussions as the Phase I and Phase II work progressed. Many of these technical findings were reflected in NERC's actions and initiatives of February 10, 2004. In turn, NERC's actions and initiatives received significant attention in the development of the Task Force's recommendations.

The SWG convened in January 2004 in Ottawa to review the Interim Report. The SWG also held virtual meetings with the investigative team leads and working group members.

Similarly, the ESWG conducted weekly telephone conferences and it held face-to-face meetings on January 30, March 3, and March 18, 2004.

Appendix C

List of Commenters

The individuals listed below either commented on the Interim Report, provided suggestions for recommendations to improve reliability, or both. Their input was greatly appreciated. Their comments can be viewed in full or in summary at http://www.nrcan.gc.ca or at http://www.electricity.doe.gov.

Abbott, Richard E.	Personal comment
Adams, Tom	Energy Probe
Akerlund, John	Uninterruptible Power Networks UPN AB
Alexander, Anthony J.	FirstEnergy
Allen, Eric	New York ISO
Barrie, David	Hydro One
Benjamin, Don	North American Electric Reliability Council (NERC)
Besich, Tom	Electric power engineer
Blasiak, James L.	DykemaGossett PLLC for International Transmission Company (ITC)
Booth, Chris	Experienced Consultants LLC
Boschmann, Armin	Manitoba Hydro
Brown, Glenn W.	New Brunswick Power Corp; NPCC Representative & Chairman, NERC Disturbance Analysis Working Group
Burke, Thomas J.	Orion Associates International, Inc.
Burrell, Carl	IMO Ontario
Bush, Tim	Consulting
Calimano, Michael	New York ISO
Cañizares, Claudio A.	University of Waterloo, Ontario Canada
Carpentier, Philippe	French grid operator
Carson, Joseph P.	Personal comment
Casazza, J. A.	Power Engineers Seeking Truth
Chen, Shihe	Power Systems Business Group, CLP Power Hong Kong Ltd.
Church, Bob	Management Consulting Services, Inc.
Clark, Harrison	Harrison K. Clark
Cook, David	NERC
Cummings, Bob	Director of Reliability Assessments and Support Services, NERC
Das, K K	IEEE member, PowerGrid Corporation of India Limited
Delea, F. J.	Power Engineers Seeking Truth
Delea, Frank	ConEdison
Divan, Deepak	Soft Switching Technologies
Doumtchenko, Victoria	MPR Associates
Duran, Pat	IMO Ontario
Durkin, Charles J.	Northeast Power Coordinating Council (NPCC)
Eggertson, Bill	Canadian Association for Renewable Energies

Fernandez, Rick	Personal comment
Fidrych, Mark	Western Area Power Authority (WAPA) and Chairman of the NERC Operating Committee
Furuya, Toshihiko	Tokyo Electric Power Co., Inc.
Galatic, Alex	Personal comment
Garg, Ajay	Hydro One Networks Inc.
Goffin, Dave	Canadian Chemical Producers Assocation
Gruber, William M. Ondrey	Attorney
Guimond, Pierre	Canadian Nuclear Association
Gurdziel, Tom	Personal comment
Hakobyan, Spartak and Gurgen	Personal comment
Han, Masur	Personal comment
Hauser, Carl	School of Electrical Engineering and Computer Science, Washington State University
Hebert, Larry	Thunder Bay Hydro
Hilt, Dave	NERC
Hughes, John P.	ELCON
Imai, Shinichi	Tokyo Electric Power
Jeyapalan, Jey K.	Jeyapalan & Associates, LLC
Johnston, Sidney A.	Personal comment
Kane, Michael	Personal comment
Katsuras, George	Independent Electric Market Operator of Ontario
Kellat, Stephen	Personal comment
Kerr, Jack	Dominion Virginia Power
Kerr, Jack	Best Real-time Reliability Analysis Practices Task Force
Kershaw, Raymond K.	International Transmission Company
Kolodziej, Eddie	Personal comment
Konow, Hans	Canadian Electricity Association
Kormos, Mike	PJM
Kucey, Tim	National Energy Board (Canada)
Laugier, Alexandre	Personal comment
Lawson, Barry	National Rural Electric Cooperative Association
Lazarewicz, Matthew L.	Beacon Power Corp.
Lee, Stephen	Electric Power Research Institute
Leovy, Steve	Personal comment
Linda Campbell	Florida Reliability Coordinating Council
Loehr, G.C.	Power Engineers Seeking Truth
Love, Peter	Canadian Energy Efficiency Alliance
Macedo, Frank	Hydro One
Maliszewski, R.M.	Power Engineers Seeking Truth
McMonagle, Rob	Canadian Solar Industries Assocation
Meissner, Joseph	Personal comment

Middlestadt, Bill	Bonneville Power Administration
Milter, Carolyn	Cuyahoga County Board of Commissioners, and member, Community Advisory Panel; panel created for Cleveland Electric Illuminating Co. (later First Energy)
Mitchell, Terry	Excel Energy
Moore, Scott	AEP
Murphy, Paul	IMO Ontario
Museler, William J.	New York Independent System Operator
O'Keefe, Brian	Canadian Union of Public Employees
Oliver, Fiona	Canadian Energy Efficiency Alliance
Ormund, Peter	Mohawk College
Pennstone, Mike	Hydro One
Pereira, Les	Personal comment
Phillips, Margie	Pennsylvania Services Integration Consortium
Rocha, Paul X.	CenterPoint Energy
Ross, Don	Prince Edward Island Wind Co-Op
Rupp, Douglas B	Ada Core Technologies, Inc.
Sasson, Mayer	New York State Reliability Council
Schwerdt, Ed	Northeast Power Coordinating Council
Seppa, Tapani O.	The Valley Group, Inc.,
Silverstein, Alison	Federal Energy Regulatory Commission
Spears, J.	Personal comment
Spencer, Sidney	Personal comment
spider	Personal comment
Staniford, Stuart	Personal comment
Stephens, Eric B.	Ohio Consumers' Counsel (OCC)
Stewart, Bob	PG&E
Synesiou, John	IMS Corporation
Tarler, Howard A.	On behalf of Chairman William M. Flynn, New York State Department of Public Service
Tatro, Phil	National Grid Company
Taylor, Carson	Bonneville Power Administration
van Welie, Gordon	ISO New England Inc.
Van Zandt, Vickie	Bonneville Power Administration
Warren, Kim	IMO Ontario
Watkins, Don	Bonneville Power Administration
Wells, Chuck	OSISoft
Wiedman, Tom	ConEd
Wightman, Donald	Utility Workers Union of America
Wilson, John	Personal comment
Winter, Chris	Conservation Council of Ontario
Wright, C. Dortch	On behalf of New Jersey Governor James E. McGreevey
Zwergel, Dave	Midwest ISO

Appendix D

NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts

Preamble

The Board of Trustees recognizes the paramount importance of a reliable bulk electric system in North America. In consideration of the findings of the investigation into the August 14, 2003 blackout, NERC must take firm and immediate actions to increase public confidence that the reliability of the North American bulk electric system is being protected.

A key finding of the blackout investigators is that violations of existing NERC reliability standards contributed directly to the blackout. Pending enactment of federal reliability legislation creating a framework for enforcement of mandatory reliability standards, and with the encouragement of the Stakeholders Committee, the board is determined to obtain full compliance with all existing and future reliability standards and intends to use all legitimate means available to achieve that end. The board therefore resolves to:

- *Receive specific information on all violations of NERC standards, including the identities of the parties involved;*
- *Take firm actions to improve compliance with NERC reliability standards;*
- *Provide greater transparency to violations of standards, while respecting the confidential nature of some information and the need for a fair and deliberate due process; and*
- *Inform and work closely with the Federal Energy Regulatory Commission and other applicable federal, state, and provincial regulatory authorities in the United States, Canada, and Mexico as needed to ensure public interests are met with respect to compliance with reliability standards.*

The board expresses its appreciation to the blackout investigators and the Steering Group for their objective and thorough work in preparing a report of recommended NERC actions. With a few clarifications, the board approves the report and directs implementation of the recommended actions. The board holds the assigned committees and organizations accountable to report to the board the progress in completing the recommended actions, and intends itself to publicly report those results. The board recognizes the possibility that this action plan may have to be adapted as additional analysis is completed, but stresses the need to move forward immediately with the actions as stated.

Furthermore, the board directs management to immediately advise the board of any significant violations of NERC reliability standards, including details regarding the nature and potential reliability impacts of the alleged violations and the identity of parties involved. Management shall supply to the board in advance of board meetings a detailed report of all violations of reliability standards.

Finally, the board resolves to form a task force to develop guidelines for the board to consider with regard to the confidentiality of compliance information and disclosure of such information to regulatory authorities and the public.

Approved by the Board of Trustees 1
February 10, 2004

Overview of Investigation Conclusions

The North American Electric Reliability Council (NERC) has conducted a comprehensive investigation of the August 14, 2003 blackout. The results of NERC's investigation contributed significantly to the U.S./Canada Power System Outage Task Force's November 19, 2003 Interim Report identifying the root causes of the outage and the sequence of events leading to and during the cascading failure. NERC fully concurs with the conclusions of the Interim Report and continues to provide its support to the Task Force through ongoing technical analysis of the outage. Although an understanding of what happened and why has been resolved for most aspects of the outage, detailed analysis continues in several areas, notably dynamic simulations of the transient phases of the cascade and a final verification of the full scope of all violations of NERC and regional reliability standards that occurred leading to the outage.

From its investigation of the August 14 blackout, NERC concludes that:

- Several entities violated NERC operating policies and planning standards, and those violations contributed directly to the start of the cascading blackout.
- The existing process for monitoring and assuring compliance with NERC and regional reliability standards was shown to be inadequate to identify and resolve specific compliance violations before those violations led to a cascading blackout.
- Reliability coordinators and control areas have adopted differing interpretations of the functions, responsibilities, authorities, and capabilities needed to operate a reliable power system.
- Problems identified in studies of prior large-scale blackouts were repeated, including deficiencies in vegetation management, operator training, and tools to help operators better visualize system conditions.
- In some regions, data used to model loads and generators were inaccurate due to a lack of verification through benchmarking with actual system data and field testing.
- Planning studies, design assumptions, and facilities ratings were not consistently shared and were not subject to adequate peer review among operating entities and regions.
- Available system protection technologies were not consistently applied to optimize the ability to slow or stop an uncontrolled cascading failure of the power system.

Overview of Recommendations

The Board of Trustees approves the NERC Steering Group recommendations to address these shortcomings. The recommendations fall into three categories.

Actions to Remedy Specific Deficiencies: Specific actions directed to First Energy (FE), the Midwest Independent System Operator (MISO), and the PJM Interconnection, LLC (PJM) to correct the deficiencies that led to the blackout.

1. Correct the Direct Causes of the August 14, 2003 Blackout.

Strategic Initiatives: Strategic initiatives by NERC and the regional reliability councils to strengthen compliance with existing standards and to formally track completion of recommended actions from August 14, and other significant power system events.

2. Strengthen the NERC Compliance Enforcement Program.
3. Initiate Control Area and Reliability Coordinator Reliability Readiness Audits.
4. Evaluate Vegetation Management Procedures and Results.
5. Establish a Program to Track Implementation of Recommendations.

Technical Initiatives: Technical initiatives to prevent or mitigate the impacts of future cascading blackouts.

6. Improve Operator and Reliability Coordinator Training
7. Evaluate Reactive Power and Voltage Control Practices.
8. Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
9. Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities and Authorities.
10. Establish Guidelines for Real-Time Operating Tools.
11. Evaluate Lessons Learned During System Restoration.
12. Install Additional Time-Synchronized Recording Devices as Needed.
13. Reevaluate System Design, Planning and Operating Criteria.
14. Improve System Modeling Data and Data Exchange Practices.

Market Impacts

Many of the recommendations in this report have implications for electricity markets and market participants, particularly those requiring reevaluation or clarification of NERC and regional standards, policies and criteria. Implicit in these recommendations is that the NERC board charges the Market Committee with assisting in the implementation of the recommendations and interfacing with the North American Energy Standards Board with respect to any necessary business practices.

Recommendation to Remedy Specific Deficiencies

Recommendation 1. Correct the Direct Causes of the August 14, 2003 Blackout.

NERC's technical analysis of the August 14 blackout leads it to fully concur with the Task Force Interim Report regarding the direct causes of the blackout. The report stated that the principal causes of the blackout were that FE did not maintain situational awareness of conditions on its power system and did not adequately manage tree growth in its transmission rights-of-way. Contributing factors included ineffective diagnostic support provided by MISO as the reliability coordinator for FE and ineffective communications between MISO and PJM.

NERC will take immediate and firm actions to ensure that the same deficiencies that were directly causal to the August 14 blackout are corrected. These steps are necessary to assure electricity customers, regulators and others with an interest in the reliable delivery of electricity that the power system is being operated in a manner that is safe and reliable, and that the specific causes of the August 14 blackout have been identified and fixed.

Recommendation 1a: FE, MISO, and PJM shall each complete the remedial actions designated in Attachment A for their respective organizations and certify to the NERC board no later than June 30, 2004, that these specified actions have been completed. Furthermore, each organization shall present its detailed plan for completing these actions to the NERC committees for technical review on March 23-24, 2004, and to the NERC board for approval no later than April 2, 2004.

Recommendation 1b: The NERC Technical Steering Committee shall immediately assign a team of experts to assist FE, MISO, and PJM in developing plans that adequately address the issues listed in Attachment A, and other remedial actions for which each entity may seek technical assistance.

Strategic Initiatives to
Assure Compliance with Reliability Standards and to Track Recommendations

Recommendation 2. Strengthen the NERC Compliance Enforcement Program.

NERC's analysis of the actions and events leading to the August 14 blackout leads it to conclude that several violations of NERC operating policies contributed directly to an uncontrolled, cascading outage on the Eastern Interconnection. NERC continues to investigate additional violations of NERC and regional reliability standards and expects to issue a final report of those violations in March 2004.

In the absence of enabling legislation in the United States and complementary actions in Canada and Mexico to authorize the creation of an electric reliability organization, NERC lacks legally sanctioned authority to enforce compliance with its reliability rules. However, the August 14 blackout is a clear signal that voluntary compliance with reliability rules is no longer adequate. NERC and the regional reliability councils must assume firm authority to measure compliance, to more transparently report significant violations that could risk the integrity of the interconnected power system, and to take immediate and effective actions to ensure that such violations are corrected.

Violations of NERC standards identified in the November 19, 2003 Interim Report:

1. Following the outage of the Chamberlin-Harding 345 kV line, FE did not take the necessary actions to return the system to a safe operating state within 30 minutes (violation of NERC Operating Policy 2).
2. FE did not notify other systems of an impending system emergency (violation of NERC Operating Policy 5).
3. FE's analysis tools were not used to effectively assess system conditions (violation of NERC Operating Policy 5).
4. FE operator training was inadequate for maintaining reliable conditions (violation of NERC Operating Policy 8).
5. MISO did not notify other reliability coordinators of potential problems (violation of NERC Operating Policy 9).

Recommendation 2a: Each regional reliability council shall report to the NERC Compliance Enforcement Program within one month of occurrence all significant[1] violations of NERC operating policies and planning standards and regional standards, whether verified or still under investigation. Such reports shall confidentially note details regarding the nature and potential reliability impacts of the alleged violations and the identity of parties involved. Additionally, each regional reliability council shall report quarterly to NERC, in a format prescribed by NERC, all violations of NERC and regional reliability council standards.

Recommendation 2b: Being presented with the results of the investigation of any significant violation, and with due consideration of the surrounding facts and circumstances, the NERC board shall require an offending organization to correct the violation within a specified time. If the board determines that an offending organization is non-responsive and continues to cause a risk to the reliability of the interconnected power systems, the board will seek to remedy the violation by requesting assistance of the appropriate regulatory authorities in the United States, Canada, and Mexico.

[1] Although all violations are important, a significant violation is one that could directly reduce the integrity of the interconnected power systems or otherwise cause unfavorable risk to the interconnected power systems. By contrast, a violation of a reporting or administrative requirement would not by itself generally be considered a significant violation.

Recommendation 2c: The Planning and Operating Committees, working in conjunction with the Compliance Enforcement Program, shall review and update existing approved and draft compliance templates applicable to current NERC operating policies and planning standards; and submit any revisions or new templates to the board for approval no later than March 31, 2004. To expedite this task, the NERC President shall immediately form a Compliance Template Task Force comprised of representatives of each committee. The Compliance Enforcement Program shall issue the board-approved compliance templates to the regional reliability councils for adoption into their compliance monitoring programs.

This effort will make maximum use of existing approved and draft compliance templates in order to meet the aggressive schedule. The templates are intended to include all existing NERC operating policies and planning standards but can be adapted going forward to incorporate new reliability standards as they are adopted by the NERC board for implementation in the future.

When the investigation team's final report on the August 14 violations of NERC and regional standards is available in March, it will be important to assess and understand the lapses that allowed violations to go unreported until a large-scale blackout occurred.

Recommendation 2d: The NERC Compliance Enforcement Program and ECAR shall, within three months of the issuance of the final report from the Compliance and Standards investigation team, evaluate the identified violations of NERC and regional standards, as compared to previous compliance reviews and audits for the applicable entities, and develop recommendations to improve the compliance process.

Recommendation 3. Initiate Control Area and Reliability Coordinator Reliability Readiness Audits.

In conducting its investigation, NERC found that deficiencies in control area and reliability coordinator capabilities to perform assigned reliability functions contributed to the August 14 blackout. In addition to specific violations of NERC and regional standards, some reliability coordinators and control areas were deficient in the performance of their reliability functions and did not achieve a level of performance that would be considered acceptable practice in areas such as operating tools, communications, and training. In a number of cases there was a lack of clarity in the NERC policies with regard to what is expected of a reliability coordinator or control area. Although the deficiencies in the NERC policies must be addressed (see Recommendation 9), it is equally important to recognize that standards cannot prescribe all aspects of reliable operation and that minimum standards present a threshold, not a target for performance. Reliability coordinators and control areas must perform well, particularly under emergency conditions, and at all times strive for excellence in their assigned reliability functions and responsibilities.

Recommendation 3a: The NERC Compliance Enforcement Program and the regional reliability councils shall jointly establish a program to audit the reliability readiness of all reliability coordinators and control areas, with immediate attention given to addressing the deficiencies identified in the August 14 blackout investigation. Audits of all control areas and reliability coordinators shall be completed within three years and continue in a three-year cycle. The 20 highest priority audits, as determined by the Compliance Enforcement Program, will be completed by June 30, 2004.

Recommendation 3b: NERC will establish a set of baseline audit criteria to which regional criteria may be added. The control area requirements will be based on the existing NERC Control Area Certification Procedure. Reliability coordinator audits will include evaluation of reliability plans, procedures, processes, tools, personnel qualifications, and training. In addition to reviewing written documents, the audits will carefully examine the actual practices and preparedness of control areas and reliability coordinators.

Recommendation 3c: The reliability regions, with the oversight and direct participation of NERC, will audit each control area's and reliability coordinator's readiness to meet these audit criteria. FERC and other relevant regulatory agencies will be invited to participate in the audits, subject to the same confidentiality conditions as the other members of the audit teams.

Recommendation 4. Evaluate Vegetation Management Procedures and Results.

Ineffective vegetation management was a major cause of the August 14 blackout and also contributed to other historical large-scale blackouts, such on July 2-3, 1996 in the west. Maintaining transmission line rights-of-way (ROW), including maintaining safe clearances of energized lines from vegetation, under-build, and other obstructions[2] incurs a substantial ongoing cost in many areas of North America. However, it is an important investment for assuring a reliable electric system.

NERC does not presently have standards for ROW maintenance. Standards on vegetation management are particularly challenging given the great diversity of vegetation and growth patterns across North America. However, NERC's standards do require that line ratings are calculated so as to maintain safe clearances from all obstructions. Furthermore, in the United States, the National Electrical Safety Code (NESC) Rules 232, 233, and 234 detail the minimum vertical and horizontal safety clearances of overhead conductors from grounded objects and various types of obstructions. NESC Rule 218 addresses tree clearances by simply stating, "Trees that may interfere with ungrounded supply conductors should be trimmed or removed." Several states have adopted their own electrical safety codes and similar codes apply in Canada.

Recognizing that ROW maintenance requirements vary substantially depending on local conditions, NERC will focus attention initially on measuring performance as indicated by the number of high voltage line trips caused by vegetation rather than immediately move toward developing standards for

[2] Vegetation, such as the trees that caused the initial line trips in FE that led to the August 14, 2003 outage is not the only type of obstruction that can breach the safe clearance distances from energized lines. Other examples include under-build of telephone and cable TV lines, train crossings, and even nests of certain large bird species.

ROW maintenance. This approach has worked well in the Western Electricity Coordinating Council (WECC) since being instituted after the 1996 outages.

Recommendation 4a: NERC and the regional reliability councils shall jointly initiate a program to report all bulk electric system[3] transmission line trips resulting from vegetation contact[4]. The program will use the successful WECC vegetation monitoring program as a model.

Recommendation 4b: Beginning with an effective date of January 1, 2004, each transmission operator will submit an annual report of all vegetation-related high voltage line trips to its respective reliability region. Each region shall assemble a detailed annual report of vegetation-related line trips in the region to NERC no later than March 31 for the preceding year, with the first reporting to be completed by March 2005 for calendar year 2004.

Vegetation management practices, including inspection and trimming requirements, can vary significantly with geography. Additionally, some entities use advanced techniques such as planting beneficial species or applying growth retardants. Nonetheless, the events of August 14 and prior outages point to the need for independent verification that viable programs exist for ROW maintenance and that the programs are being followed.

Recommendation 4c: Each bulk electric transmission owner shall make its vegetation management procedure, and documentation of work completed, available for review and verification upon request by the applicable regional reliability council, NERC, or applicable federal, state or provincial regulatory agency.

Should this approach of monitoring vegetation-related line outages and procedures prove ineffective in reducing the number of vegetation-related line outages, NERC will consider the development of minimum line clearance standards to assure reliability.

Recommendation 5. Establish a Program to Track Implementation of Recommendations.

The August 14 blackout shared a number of contributing factors with prior large-scale blackouts, including:

- Conductors contacting trees
- Ineffective visualization of power system conditions and lack of situational awareness
- Ineffective communications
- Lack of training in recognizing and responding to emergencies
- Insufficient static and dynamic reactive power supply
- Need to improve relay protection schemes and coordination

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[3] All transmission lines operating at 230 kV and higher voltage, and any other lower voltage lines designated by the regional reliability council to be critical to the reliability of the bulk electric system, shall be included in the program.
[4] A line trip includes a momentary opening and reclosing of the line, a lock out, or a combination. For reporting purposes, all vegetation-related openings of a line occurring within one 24-hour period should be considered one event. Trips known to be caused by severe weather or other natural disaster such as earthquake are excluded. Contact with vegetation includes both physical contact and arcing due to insufficient clearance.

It is important that recommendations resulting from system outages be adopted consistently by all regions and operating entities, not just those directly affected by a particular outage. Several lessons learned prior to August 14, if heeded, could have prevented the outage. WECC and NPCC, for example, have programs that could be used as models for tracking completion of recommendations. NERC and some regions have not adequately tracked completion of recommendations from prior events to ensure they were consistently implemented.

Recommendation 5a: NERC and each regional reliability council shall establish a program for documenting completion of recommendations resulting from the August 14 blackout and other historical outages, as well as NERC and regional reports on violations of reliability standards, results of compliance audits, and lessons learned from system disturbances. Regions shall report quarterly to NERC on the status of follow-up actions to address recommendations, lessons learned, and areas noted for improvement. NERC staff shall report both NERC activities and a summary of regional activities to the board.

Assuring compliance with reliability standards, evaluating the reliability readiness of reliability coordinators and control areas, and assuring recommended actions are achieved will be effective steps in reducing the chances of future large-scale outages. However, it is important for NERC to also adopt a process for continuous learning and improvement by seeking continuous feedback on reliability performance trends, not rely mainly on learning from and reacting to catastrophic failures.

Recommendation 5b: NERC shall by January 1, 2005 establish a reliability performance monitoring function to evaluate and report bulk electric system reliability performance.

Such a function would assess large-scale outages and near misses to determine root causes and lessons learned, similar to the August 14 blackout investigation. This function would incorporate the current Disturbance Analysis Working Group and expand that work to provide more proactive feedback to the NERC board regarding reliability performance. This program would also gather and analyze reliability performance statistics to inform the board of reliability trends. This function could develop procedures and capabilities to initiate investigations in the event of future large-scale outages or disturbances. Such procedures and capabilities would be shared between NERC and the regional reliability councils for use as needed, with NERC and regional investigation roles clearly defined in advance.

Technical Initiatives to Minimize the Likelihood and Impacts of Possible Future Cascading Outages

Recommendation 6. Improve Operator and Reliability Coordinator Training.

NERC found during its investigation that some reliability coordinators and control area operators had not received adequate training in recognizing and responding to system emergencies. Most notable was the lack of realistic simulations and drills for training and verifying the capabilities of operating personnel. This training deficiency contributed to the lack of situational awareness and failure to declare an emergency when operator intervention was still possible prior to the high speed portion of the sequence of events.

Recommendation 6: All reliability coordinators, control areas, and transmission operators shall provide at least five days per year of training and drills in system emergencies, using realistic simulations[5], for each staff person with responsibility for the real-time operation or reliability monitoring of the bulk electric system. This system emergency training is in addition to other training requirements. Five days of system emergency training and drills are to be completed prior to June 30, 2004, with credit given for documented training already completed since July 1, 2003. Training documents, including curriculum, training methods, and individual training records, are to be available for verification during reliability readiness audits.

NERC has published Continuing Education Criteria specifying appropriate qualifications for continuing education providers and training activities.

In the longer term, the NERC Personnel Certification Governance Committee (PCGC), which is independent of the NERC board, should explore expanding the certification requirements of system operating personnel to include additional measures of competency in recognizing and responding to system emergencies. The current NERC certification examination is a written test of the NERC Operating Manual and other references relating to operator job duties, and is not by itself intended to be a complete demonstration of competency to handle system emergencies.

Recommendation 7. Evaluate Reactive Power and Voltage Control Practices.

The August 14 blackout investigation identified inconsistent practices in northeastern Ohio with regard to the setting and coordination of voltage limits and insufficient reactive power supply. Although the deficiency of reactive power supply in northeastern Ohio did not directly cause the blackout, it was a contributing factor and was a significant violation of existing reliability standards.

In particular, there appear to have been violations of NERC Planning Standard I.D.S1 requiring static and dynamic reactive power resources to meet the performance criteria specified in Table I of

[5] The term "realistic simulations" includes a variety of tools and methods that present operating personnel with situations to improve and test diagnostic and decision-making skills in an environment that resembles expected conditions during a particular type of system emergency. Although a full replica training simulator is one approach, lower cost alternatives such as PC-based simulators, tabletop drills, and simulated communications can be effective training aids if used properly.

Planning Standard I.A on Transmission Systems. Planning Standard II.B.S1 requires each regional reliability council to establish procedures for generating equipment data verification and testing, including reactive power capability. Planning Standard III.C.S1 requires that all synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator. S2 of this standard also requires that generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units.

On one hand, the unsafe conditions on August 14 with respect to voltage in northeastern Ohio can be said to have resulted from violations of NERC planning criteria for reactive power and voltage control, and those violations should have been identified through the NERC and ECAR compliance monitoring programs (addressed by Recommendation 2). On the other hand, investigators believe these deficiencies are also symptomatic of a systematic breakdown of the reliability studies and practices in FE and the ECAR region that allowed unsafe voltage criteria to be set and used in study models and operations. There were also issues identified with reactive characteristics of loads, as addressed in Recommendation 14.

Recommendation 7a: The Planning Committee shall reevaluate within one year the effectiveness of the existing reactive power and voltage control standards and how they are being implemented in practice in the ten NERC regions. Based on this evaluation, the Planning Committee shall recommend revisions to standards or process improvements to ensure voltage control and stability issues are adequately addressed.

Recommendation 7b: ECAR shall no later than June 30, 2004 review its reactive power and voltage criteria and procedures, verify that its criteria and procedures are being fully implemented in regional and member studies and operations, and report the results to the NERC board.

Recommendation 8. Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.

The importance of automatic control and protection systems in preventing, slowing, or mitigating the impact of a large-scale outage cannot be stressed enough. To underscore this point, following the trip of the Sammis-Star line at 4:06, the cascading failure into parts of eight states and two provinces, including the trip of over 531 generating units and over 400 transmission lines, was completed in the next eight minutes. Most of the event sequence, in fact, occurred in the final 12 seconds of the cascade. Likewise, the July 2, 1996 failure took less than 30 seconds and the August 10, 1996 failure took only 5 minutes. It is not practical to expect operators will always be able to analyze a massive, complex system failure and to take the appropriate corrective actions in a matter of a few minutes. The NERC investigators believe that two measures would have been crucial in slowing or stopping the uncontrolled cascade on August 14:

- Better application of zone 3 impedance relays on high voltage transmission lines
- Selective use of under-voltage load shedding.

First, beginning with the Sammis-Star line trip, most of the remaining line trips during the cascade phase were the result of the operation of a zone 3 relay for a perceived overload (a combination of high amperes and low voltage) on the protected line. If used, zone 3 relays typically act as an overreaching backup to the zone 1 and 2 relays, and are not intentionally set to operate on a line overload. However, under extreme conditions of low voltages and large power swings as seen on August 14, zone 3 relays can operate for overload conditions and propagate the outage to a wider area by essentially causing the system to "break up". Many of the zone 3 relays that operated during the August 14 cascading outage were not set with adequate margins above their emergency thermal ratings. For the short times involved, thermal heating is not a problem and the lines should not be tripped for overloads. Instead, power system protection devices should be set to address the specific condition of concern, such as a fault, out-of-step condition, etc., and should not compromise a power system's inherent physical capability to slow down or stop a cascading event.

Recommendation 8a: All transmission owners shall, no later than September 30, 2004, evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions[6]. In each case that a zone 3 relay is set so as to trip on load under extreme conditions, the transmission operator shall reset, upgrade, replace, or otherwise mitigate the overreach of those relays as soon as possible and on a priority basis, but no later than December 31, 2005. Upon completing analysis of its application of zone 3 relays, each transmission owner may no later than December 31, 2004 submit justification to NERC for applying zone 3 relays outside of these recommended parameters. The Planning Committee shall review such exceptions to ensure they do not increase the risk of widening a cascading failure of the power system.

A second key finding with regard to system protection was that if an automatic under-voltage load shedding scheme had been in place in the Cleveland-Akron area on August 14, there is a high probability the outage could have been limited to that area.

Recommendation 8b: Each regional reliability council shall complete an evaluation of the feasibility and benefits of installing under-voltage load shedding capability in load centers within the region that could become unstable as a result of being deficient in reactive power following credible multiple-contingency events. The regions are to complete the initial studies and report the results to NERC within one year. The regions are requested to promote the installation of under-voltage load shedding capabilities within critical areas, as determined by the studies to be effective in preventing an uncontrolled cascade of the power system.

The NERC investigation of the August 14 blackout has identified additional transmission and generation control and protection issues requiring further analysis. One concern is that generating unit control and protection schemes need to consider the full range of possible extreme system conditions, such as the low voltages and low and high frequencies experienced on August 14. The team also noted that improvements may be needed in under-frequency load shedding and its coordination with generator under-and over-frequency protection and controls.

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[6] The NERC investigation team recommends that the zone 3 relay, if used, should not operate at or below 150% of the emergency ampere rating of a line, assuming a .85 per unit voltage and a line phase angle of 30 degrees.

Recommendation 8c: The Planning Committee shall evaluate Planning Standard III – System Protection and Control and propose within one year specific revisions to the criteria to adequately address the issue of slowing or limiting the propagation of a cascading failure. The board directs the Planning Committee to evaluate the lessons from August 14 regarding relay protection design and application and offer additional recommendations for improvement.

Recommendation 9. Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities and Authorities.

Ambiguities in the NERC operating policies may have allowed entities involved in the August 14 blackout to make different interpretations regarding the functions, responsibilities, capabilities, and authorities of reliability coordinators and control areas. Characteristics and capabilities necessary to enable prompt recognition and effective response to system emergencies must be specified.

The lack of timely and accurate outage information resulted in degraded performance of state estimator and reliability assessment functions on August 14. There is a need to review options for sharing of outage information in the operating time horizon (e.g. 15 minutes or less), so as to ensure the accurate and timely sharing of outage data necessary to support real-time operating tools such as state estimators, real-time contingency analysis, and other system monitoring tools.

On August 14, reliability coordinator and control area communications regarding conditions in northeastern Ohio were ineffective, and in some cases confusing. Ineffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade. Consistent application of effective communications protocols, particularly during emergencies, is essential to reliability. Alternatives should be considered to one-on-one phone calls during an emergency to ensure all parties are getting timely and accurate information with a minimum number of calls.

NERC operating policies do not adequately specify critical facilities, leaving ambiguity regarding which facilities must be monitored by reliability coordinators. Nor do the policies adequately define criteria for declaring transmission system emergencies. Operating policies should also clearly specify that curtailing interchange transactions through the NERC Transmission Loading Relief (TLR) Procedure is not intended as a method for restoring the system from an actual Operating Security Limit violation to a secure operating state.

Recommendation 9: The Operating Committee shall complete the following by June 30, 2004:

- **Evaluate and revise the operating policies and procedures, or provide interpretations, to ensure reliability coordinator and control area functions, responsibilities, and authorities are completely and unambiguously defined.**
- **Evaluate and improve the tools and procedures for operator and reliability coordinator communications during emergencies.**
- **Evaluate and improve the tools and procedures for the timely exchange of outage information among control areas and reliability coordinators.**

Recommendation 10. Establish Guidelines for Real-Time Operating Tools.

The August 14 blackout was caused by a lack of situational awareness that was in turn the result of inadequate reliability tools and backup capabilities. Additionally, the failure of FE's control computers and alarm system contributed directly to the lack of situational awareness. Likewise, MISO's incomplete tool set and the failure of its state estimator to work effectively on August 14 contributed to the lack of situational awareness.

Recommendation 10: The Operating Committee shall within one year evaluate the real-time operating tools necessary for reliable operation and reliability coordination, including backup capabilities. The Operating Committee is directed to report both minimum acceptable capabilities for critical reliability functions and a guide of best practices.

This evaluation should include consideration of the following:

- Modeling requirements, such as model size and fidelity, real and reactive load modeling, sensitivity analyses, accuracy analyses, validation, measurement, observability, update procedures, and procedures for the timely exchange of modeling data.
- State estimation requirements, such as periodicity of execution, monitoring external facilities, solution quality, topology error and measurement error detection, failure rates including times between failures, presentation of solution results including alarms, and troubleshooting procedures.
- Real-time contingency analysis requirements, such as contingency definition, periodicity of execution, monitoring external facilities, solution quality, post-contingency automatic actions, failure rates including mean/maximum times between failures, reporting of results, presentation of solution results including alarms, and troubleshooting procedures including procedures for investigating unsolvable contingencies.

Recommendation 11. Evaluate Lessons Learned During System Restoration.

The efforts to restore the power system and customer service following the outage were effective, considering the massive amount of load lost and the large number of generators and transmission lines that tripped. Fortunately, the restoration was aided by the ability to energize transmission from neighboring systems, thereby speeding the recovery. Despite the apparent success of the restoration effort, it is important to evaluate the results in more detail to determine opportunities for improvement. Blackstart and restoration plans are often developed through study of simulated conditions. Robust testing of live systems is difficult because of the risk of disturbing the system or interrupting customers. The August 14 blackout provides a valuable opportunity to apply actual events and experiences to learn to better prepare for system blackstart and restoration in the future. That opportunity should not be lost, despite the relative success of the restoration phase of the outage.

Recommendation 11a: The Planning Committee, working in conjunction with the Operating Committee, NPCC, ECAR, and PJM, shall evaluate the black start and system restoration performance following the outage of August 14, and within one year report to the NERC board the results of that evaluation with recommendations for improvement.

Recommendation 11b: All regional reliability councils shall, within six months of the Planning Committee report to the NERC board, reevaluate their procedures and plans to assure an effective blackstart and restoration capability within their region.

Recommendation 12. Install Additional Time-Synchronized Recording Devices as Needed.

A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices.

NERC Planning Standard I.F – Disturbance Monitoring does require location of recording devices for disturbance analysis. Often time, recorders are available, but they are not synchronized to a time standard. All digital fault recorders, digital event recorders, and power system disturbance recorders should be time stamped at the point of observation with a precise Global Positioning Satellite (GPS) synchronizing signal. Recording and time-synchronization equipment should be monitored and calibrated to assure accuracy and reliability.

Time-synchronized devices, such as phasor measurement units, can also be beneficial for monitoring a wide-area view of power system conditions in real-time, such as demonstrated in WECC with their Wide-Area Monitoring System (WAMS).

Recommendation 12a: The reliability regions, coordinated through the NERC Planning Committee, shall within one year define regional criteria for the application of synchronized recording devices in power plants and substations. Regions are requested to facilitate the installation of an appropriate number, type and location of devices within the region as soon as practical to allow accurate recording of future system disturbances and to facilitate benchmarking of simulation studies by comparison to actual disturbances.

Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization and, as necessary, install additional dynamic recorders.

Recommendation 13. Reevaluate System Design, Planning and Operating Criteria.

The investigation report noted that FE entered the day on August 14 with insufficient resources to stay within operating limits following a credible set of contingencies, such as the loss of the East Lake 5 unit and the Chamberlin-Harding line. NERC will conduct an evaluation of operations planning practices and criteria to ensure expected practices are sufficient and well understood. The review will reexamine fundamental operating criteria, such as n-1 and the 30-minute limit in preparing the system for a next contingency, and Table I Category C.3 of the NERC planning standards. Operations planning and operating criteria will be identified that are sufficient to ensure the system is in a known and reliable condition at all times, and that positive controls, whether manual or automatic, are available and appropriately located at all times to return the Interconnection to a secure condition. Daily operations planning, and subsequent real time operations planning will identify available system reserves to meet operating criteria.

Recommendation 13a: The Operating Committee shall evaluate operations planning and operating criteria and recommend revisions in a report to the board within one year.

Prior studies in the ECAR region did not adequately define the system conditions that were observed on August 14. Severe contingency criteria were not adequate to address the events of August 14 that led to the uncontrolled cascade. Also, northeastern Ohio was found to have insufficient reactive support to serve its loads and meet import criteria. Instances were also noted in the FE system and ECAR area of different ratings being used for the same facility by planners and operators and among entities, making the models used for system planning and operation suspect. NERC and the regional reliability councils must take steps to assure facility ratings are being determined using consistent criteria and being effectively shared and reviewed among entities and among planners and operators.

Recommendation 13b: ECAR shall no later than June 30, 2004 reevaluate its planning and study procedures and practices to ensure they are in compliance with NERC standards, ECAR Document No. 1, and other relevant criteria; and that ECAR and its members' studies are being implemented as required.

Recommendation 13c: The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, methods and practices used for system design, planning and analysis; and shall report the results and recommendations to the NERC board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information.

Regional reliability councils may consider assembling a regional database that includes the ratings of all bulk electric system (100 kV and higher voltage) transmission lines, transformers, phase angle regulators, and phase shifters. This database should be shared with neighboring regions as needed for system planning and analysis.

NERC and the regional reliability councils should review the scope, frequency, and coordination of interregional studies, to include the possible need for simultaneous transfer studies. Study criteria will be reviewed, particularly the maximum credible contingency criteria used for system analysis. Each control area will be required to identify, for both the planning and operating time horizons, the planned emergency import capabilities for each major load area.

Recommendation 14. Improve System Modeling Data and Data Exchange Practices.

The after-the-fact models developed to simulate August 14 conditions and events indicate that dynamic modeling assumptions, including generator and load power factors, used in planning and operating models were inaccurate. Of particular note, the assumptions of load power factor were overly optimistic (loads were absorbing much more reactive power than pre-August 14 models indicated). Another suspected problem is modeling of shunt capacitors under depressed voltage conditions. Regional reliability councils should establish regional power system models that enable the sharing of consistent, validated data among entities in the region. Power flow and transient stability simulations should be periodically compared (benchmarked) with actual system events to validate model data. Viable load (including load power factor) and generator testing programs are necessary to improve agreement between power flows and dynamic simulations and the actual system performance.

Recommendation 14: The regional reliability councils shall within one year establish and begin implementing criteria and procedures for validating data used in power flow models and dynamic simulations by benchmarking model data with actual system performance. Validated modeling data shall be exchanged on an inter-regional basis as needed for reliable system planning and operation.

During the data collection phase of the blackout investigation, when control areas were asked for information pertaining to merchant generation within their area, data was frequently not supplied. The reason often given was that the control area did not know the status or output of the generator at a given point in time. Another reason was the commercial sensitivity or confidentiality of such data.

Appendix E

List of Electricity Acronyms

AEP	American Electric Power
BPA	Bonneville Power Administration
CA	Control area
CNSC	Canadian Nuclear Safety Commission
DOE	Department of Energy (U.S.)
ECAR	East Central Area Reliability Coordination Agreement
EIA	Energy Information Administration (U.S. DOE)
EMS	Energy management system
ERCOT	Electric Reliability Council of Texas
ERO	Electric reliability organization
FE	FirstEnergy
FERC	Federal Energy Regulatory Commission (U.S.)
FRCC	Florida Reliability Coordinating Council
GW, GWh	Gigawatt, Gigawatt-hour
IEEE	Institute of Electrical and Electronics Engineers
IPP	Independent power producer
ISAC	Information Sharing and Analysis Center
kV, kVAr	Kilovolt, Kilovolt-Amperes-reactive
kW, kWh	Kilowatt, Kilowatt-hour
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MECS	Michigan Electrical Coordinated Systems
MVA, MVAr	Megavolt-Amperes, Megavolt-Amperes-reactive
MW, MWh	Megawatt, Megawatt-hour
NERC	North American Electric Reliability Council
NESC	National Electricity Safety Code
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission (U.S.)
NRCan	Natural Resources Canada
OASIS	Open Access Same Time Information Service
OETD	Office of Electric Transmission and Distribution (U.S. DOE)
PJM	PJM Interconnection
PUC	Public utility (or public service) commission (state)
RC	Reliability coordinator
ROW	Right-of-Way (transmission or distribution line, pipeline, etc.)
RRC	Regional reliability council
RTO	Regional Transmission Organization
SCADA	Supervisory control and data acquisition
SERC	Southeast Electric Reliability Council
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority (U.S.)
WECC	Western Electricity Coordinating Council

Appendix F

Electricity Glossary

AC: Alternating current; current that changes periodically (sinusoidally) with time.

ACE: Area Control Error in MW. A negative value indicates a condition of under-generation relative to system load and imports, and a positive value denotes over-generation.

Active Power: See "Real Power."

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

AGC: Automatic Generation Control is a computation based on measured frequency and computed economic dispatch. Generation equipment under AGC automatically responds to signals from an EMS computer in real time to adjust power output in response to a change in system frequency, tie-line loading, or to a prescribed relation between these quantities. Generator output is adjusted so as to maintain a target system frequency (usually 60 Hz) and any scheduled MW interchange with other areas.

Apparent Power: The product of voltage and current phasors. It comprises both active and reactive power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Blackstart Capability: The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the bulk electric system.

Bulk Electric System: A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system.

Bulk Transmission: A functional or voltage classification relating to the higher voltage portion of the transmission system, specifically, lines at or above a voltage level of 115 kV.

Bus: Shortened from the word busbar, meaning a node in an electrical network where one or more elements are connected together.

Capacitor Bank: A capacitor is an electrical device that provides reactive power to the system and is often used to compensate for reactive load and help support system voltage. A bank is a collection of one or more capacitors at a single location.

Capacity: The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.

Cascading: The uncontrolled successive loss of system elements triggered by an incident. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Circuit: A conductor or a system of conductors through which electric current flows.

Circuit Breaker: A switching device connected to the end of a transmission line capable of opening or closing the circuit in response to a command, usually from a relay.

Control Area: An electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to: (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load in the electric power system(s); (2) maintain, within the limits of Good Utility Practice, scheduled interchange with other Control Areas; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Contingency: The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Control Area Operator: An individual or organization responsible for controlling generation to maintain interchange schedule with other control areas and contributing to the frequency regulation of the interconnection. The control area is an electric system that is bounded by interconnection metering and telemetry.

Current (Electric): The rate of flow of electrons in an electrical conductor measured in Amperes.

Curtailability: The right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

Demand: The rate at which electric energy is delivered to consumers or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Also see "Load."

DC: Direct current; current that is steady and does not change sinusoidally with time (see "AC").

Dispatch Operator: Control of an integrated electric system involving operations such as assignment of levels of output to specific generating stations and other sources of supply; control of transmission lines, substations, and equipment; operation of principal interties and switching; and scheduling of energy transactions.

Distribution: For electricity, the function of distributing electric power using low voltage lines to retail customers.

Distribution Network: The portion of an electric system that is dedicated to delivering electric energy to an end user, at or below 69 kV. The distribution network consists primarily of low-voltage lines and transformers that "transport" electricity from the bulk power system to retail customers.

Disturbance: An unplanned event that produces an abnormal system condition.

Electrical Energy: The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).

Electric Utility: Person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy primarily for use by the public, and is defined as a utility under the statutes and rules by which it is regulated. An electric utility can be investor-owned, cooperatively owned, or government-owned (by a federal agency, crown corporation, State, provincial government, municipal government, and public power district).

Element: Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Energy Emergency: A condition when a system or power pool does not have adequate energy resources (including water for hydro units) to supply its customers' expected energy requirements.

Emergency: Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system.

Emergency Voltage Limits: The operating voltage range on the interconnected systems that is acceptable for the time, sufficient for system adjustments to be made following a facility outage or system disturbance.

EMS: An energy management system is a computer control system used by electric utility dispatchers to monitor the real time performance of various elements of an electric system and to control generation and transmission facilities.

Fault: A fault usually means a short circuit, but more generally it refers to some abnormal system condition. Faults are often random events.

Federal Energy Regulatory Commission (FERC): Independent Federal agency that, among other responsibilities, regulates the transmission and wholesale sales of electricity in interstate commerce.

Flashover: A plasma arc initiated by some event such as lightning. Its effect is a short circuit on the network.

Flowgate: A single or group of transmission elements intended to model MW flow impact relating to transmission limitations and transmission service usage.

Forced Outage: The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Frequency: The number of complete alternations or cycles per second of an alternating current, measured in Hertz. The standard frequency in the

United States is 60 Hz. In some other countries the standard is 50 Hz.

Frequency Deviation or Error: A departure from scheduled frequency; the difference between actual system frequency and the scheduled system frequency.

Frequency Regulation: The ability of a Control Area to assist the interconnected system in maintaining scheduled frequency. This assistance can include both turbine governor response and automatic generation control.

Frequency Swings: Constant changes in frequency from its nominal or steady-state value.

Generation (Electricity): The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt hours (kWh) or megawatt hours (MWh).

Generator: Generally, an electromechanical device used to convert mechanical power to electrical power.

Grid: An electrical transmission and/or distribution network.

Grid Protection Scheme: Protection equipment for an electric power system, consisting of circuit breakers, certain equipment for measuring electrical quantities (e.g., current and voltage sensors) and devices called relays. Each relay is designed to protect the piece of equipment it has been assigned from damage. The basic philosophy in protection system design is that any equipment that is threatened with damage by a sustained fault is to be automatically taken out of service.

Ground: A conducting connection between an electrical circuit or device and the earth. A ground may be intentional, as in the case of a safety ground, or accidental, which may result in high overcurrents.

Imbalance: A condition where the generation and interchange schedules do not match demand.

Impedance: The total effects of a circuit that oppose the flow of an alternating current consisting of inductance, capacitance, and resistance. It can be quantified in the units of ohms.

Independent System Operator (ISO): An organization responsible for the reliable operation of the power grid under its purview and for providing open transmission access to all market participants on a nondiscriminatory basis. An ISO is usually not-for-profit and can advise utilities within its territory on transmission expansion and maintenance but does not have the responsibility to carry out the functions.

Interchange: Electric power or energy that flows across tie-lines from one entity to another, whether scheduled or inadvertent.

Interconnected System: A system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

Interconnection: When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT (Texas), Québec, and Alaska. When not capitalized, the facilities that connect two systems or Control Areas. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a Control Area or system.

Interface: The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.

ISAC: Information Sharing and Analysis Centers (ISACs) are designed by the private sector and serve as a mechanism for gathering, analyzing, appropriately sanitizing and disseminating private sector information. These centers could also gather, analyze, and disseminate information from Government for further distribution to the private sector. ISACs also are expected to share important information about vulnerabilities, threats, intrusions, and anomalies, but do not interfere with direct information exchanges between companies and the Government.

Island: A portion of a power system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system elements.

Kilovar (kVAr): Unit of alternating current reactive power equal to 1,000 VArs.

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

Kilovolt-Amperes (kVA): Unit of apparent power equal to 1,000 volt amperes. Here, apparent power is in contrast to real power. On AC systems the voltage and current will not be in phase if reactive power is being transmitted.

Kilowatthour (kWh): Unit of energy equaling one thousand watthours, or one kilowatt used over one hour. This is the normal quantity used for metering and billing electricity customers. The retail price for a kWh varies from approximately 4 cents to 15 cents. At a 100% conversion efficiency, one kWh is equivalent to about 4 fluid ounces of gasoline, 3/16 pound of liquid petroleum, 3 cubic feet of natural gas, or 1/4 pound of coal.

Line Trip: Refers to the automatic opening of the conducting path provided by a transmission line by the circuit breakers. These openings or "trips" are to protect the transmission line during faulted conditions.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers. See "Demand."

Load Shedding: The process of deliberately removing (either manually or automatically) preselected customer demand from a power system in response to an abnormal condition, to maintain the integrity of the system and minimize overall customer outages.

Lockout: A state of a transmission line following breaker operations where the condition detected by the protective relaying was not eliminated by temporarily opening and reclosing the line, possibly several times. In this state, the circuit breakers cannot generally be reclosed without resetting a lockout device.

Market Participant: An entity participating in the energy marketplace by buying/selling transmission rights, energy, or ancillary services into, out of, or through an ISO-controlled grid.

Megawatthour (MWh): One million watthours.

Metered Value: A measured electrical quantity that may be observed through telemetering, supervisory control and data acquisition (SCADA), or other means.

Metering: The methods of applying devices that measure and register the amount and direction of electrical quantities with respect to time.

NERC Interregional Security Network (ISN): A communications network used to exchange electric system operating parameters in near real time among those responsible for reliable operations of the electric system. The ISN provides timely and accurate data and information exchange among reliability coordinators and other system operators. The ISN, which operates over the frame relay NERCnet system, is a private Intranet that is capable of handling additional applications between participants.

Normal (Precontingency) Operating Procedures: Operating procedures that are normally invoked by the system operator to alleviate potential facility overloads or other potential system problems in anticipation of a contingency.

Normal Voltage Limits: The operating voltage range on the interconnected systems that is acceptable on a sustained basis.

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

OASIS: Open Access Same Time Information Service (OASIS), developed by the Electric Power Research Institute, is designed to facilitate open access by providing users with access to information on transmission services and availability, plus facilities for transactions.

Operating Criteria: The fundamental principles of reliable interconnected systems operation, adopted by NERC.

Operating Guides: Operating practices that a Control Area or systems functioning as part of a Control Area may wish to consider. The application of Guides is optional and may vary among Control Areas to accommodate local conditions and individual system requirements.

Operating Policies: The doctrine developed for interconnected systems operation. This doctrine consists of Criteria, Standards, Requirements, Guides, and instructions, which apply to all Control Areas.

Operating Procedures: A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Operating Requirements: Obligations of a Control Area and systems functioning as part of a Control Area.

Operating Security Limit: The value of a system operating parameter (e.g. total power transfer across an interface) that satisfies the most limiting of prescribed pre- and post-contingency operating criteria as determined by equipment loading capability and acceptable stability and voltage conditions. It is the operating limit to be observed so that the transmission system will remain reliable even if the worst contingency occurs.

Operating Standards: The obligations of a Control Area and systems functioning as part of a Control Area that are measurable. An Operating Standard may specify monitoring and surveys for compliance.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Planning Guides: Good planning practices and considerations that Regions, subregions, power pools, or individual systems should follow. The application of Planning Guides may vary to match local conditions and individual system requirements.

Planning Policies: The framework for the reliability of interconnected bulk electric supply in terms of responsibilities for the development of and conformance to NERC Planning Principles and Guides and Regional planning criteria or guides, and NERC and Regional issues resolution processes. NERC Planning Procedures, Principles, and Guides emanate from the Planning Policies.

Planning Principles: The fundamental characteristics of reliable interconnected bulk electric systems and the tenets for planning them.

Planning Procedures: An explanation of how the Planning Policies are addressed and implemented by the NERC Engineering Committee, its subgroups, and the Regional Councils to achieve bulk electric system reliability.

Post-contingency Operating Procedures: Operating procedures that may be invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred.

Protective Relay: A device designed to detect abnormal system conditions, such as electrical shorts on the electric system or within generating plants, and initiate the operation of circuit breakers or other control equipment.

Power/Phase Angle: The angular relationship between an AC (sinusoidal) voltage across a circuit element and the AC (sinusoidal) current through it. The real power that can flow is related to this angle.

Power: See "Real Power."

Power Flow: See "Current."

Rate: The authorized charges per unite or level of consumption for a specified time period for any of the classes of utility services provided to a customer.

Rating: The operational limits of an electric system, facility, or element under a set of specified conditions.

Reactive Power: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr), and is the mathematical product of voltage and current consumed by reactive loads. Examples of reactive loads include capacitors and inductors. These types of loads, when connected to an ac voltage source, will draw current, but because the current is 90 degrees out of phase with the applied voltage, they actually consume no real power.

Readiness: The extent to which an organizational entity is prepared to meet the functional requirements set by NERC or its regional council for entities of that type or class.

Real Power: Also known as "active power." The rate at which work is performed or that energy is transferred, usually expressed in kilowatts (kW) or megawatts (MW). The terms "active power" or "real power" are often used in place of the term power alone to differentiate it from reactive power.

Real-Time Operations: The instantaneous operations of a power system as opposed to those operations that are simulated.

Regional Reliability Council: One of ten Electric Reliability Councils that form the North American Electric Reliability Council (NERC).

Regional Transmission Operator (RTO): An organization that is independent from all generation and power marketing interests and has exclusive responsibility for electric transmission grid operations, short-term electric reliability, and transmission services within a multi-State region. To achieve those objectives, the RTO manages transmission facilities owned by different companies and encompassing one, large, contiguous geographic area.

Regulations: Rules issued by regulatory authorities to implement laws passed by legislative bodies.

Relay: A device that controls the opening and subsequent reclosing of circuit breakers. Relays take measurements from local current and voltage transformers, and from communication channels connected to the remote end of the lines. A relay output trip signal is sent to circuit breakers when needed.

Relay Setting: The parameters that determine when a protective relay will initiate operation of circuit breakers or other control equipment.

Reliability: The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system, Adequacy and Security.

Reliability Coordinator: An individual or organization responsible for the safe and reliable operation of the interconnected transmission system for their defined area, in accordance with NERC reliability standards, regional criteria, and subregional criteria and practices. This entity facilitates the sharing of data and information about the status of the Control Areas for which it is responsible, establishes a security policy for these Control Areas and their interconnections, and coordinates emergency operating procedures that rely on common operating terminology, criteria, and standards.

Resistance: The characteristic of materials to restrict the flow of current in an electric circuit. Resistance is inherent in any electric wire, including those used for the transmission of electric power. Resistance in the wire is responsible for heating the wire as current flows through it and the subsequent power loss due to that heating.

Restoration: The process of returning generators and transmission system elements and restoring load following an outage on the electric system.

Right-of-Way (ROW) Maintenance: Activities by utilities to maintain electrical clearances along transmission or distribution lines.

Safe Limits: System limits on quantities such as voltage or power flows such that if the system is operated within these limits it is secure and reliable.

SCADA: Supervisory Control and Data Acquisition system; a system of remote control and telemetry used to monitor and control the electric system.

Schedule: An agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the contracting parties and the Control Area(s) involved in the transaction.

Scheduling Coordinator: An entity certified by an ISO or RTO for the purpose of undertaking scheduling functions.

Seams: The boundaries between adjacent electricity-related organizations. Differences in regulatory requirements or operating practices may create "seams problems."

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

Security Coordinator: An individual or organization that provides the security assessment and emergency operations coordination for a group of Control Areas.

Short Circuit: A low resistance connection unintentionally made between points of an electrical circuit, which may result in current flow far above normal levels.

Shunt Capacitor Bank: Shunt capacitors are capacitors connected from the power system to an electrical ground. They are used to supply kilovars (reactive power) to the system at the point where they are connected. A shunt capacitor bank is a group of shunt capacitors.

Single Contingency: The sudden, unexpected failure or outage of a system facility(s) or element(s) (generating unit, transmission line, transformer, etc.). Elements removed from service as part of the operation of a remedial action scheme are considered part of a single contingency.

Special Protection System: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components.

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Stability Limit: The maximum power flow possible through a particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.

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

Station: A node in an electrical network where one or more elements are connected. Examples include generating stations and substations.

Storage: Energy transferred form one entity to another entity that has the ability to conserve the energy (i.e., stored as water in a reservoir, coal in a pile, etc.) with the intent that the energy will be returned at a time when such energy is more useable to the original supplying entity.

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

Subtransmission: A functional or voltage classification relating to lines at voltage levels between 69kV and 115kV.

Supervisory Control and Data Acquisition (SCADA): See SCADA.

Surge: A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.

Surge Impedance Loading: The maximum amount of real power that can flow down a lossless transmission line such that the line does not require any VArs to support the flow.

Switching Station: Facility equipment used to tie together two or more electric circuits through switches. The switches are selectively arranged to permit a circuit to be disconnected, or to change the electric connection between the circuits.

Synchronize: The process of connecting two previously separated alternating current apparatuses after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).

System: An interconnected combination of generation, transmission, and distribution components comprising an electric utility and independent power producer(s) (IPP), or group of utilities and IPP(s).

System Operator: An individual at an electric system control center whose responsibility it is to monitor and control that electric system in real time.

System Reliability: A measure of an electric system's ability to deliver uninterrupted service at the proper voltage and frequency.

Thermal Limit: A power flow limit based on the possibility of damage by heat. Heating is caused by the electrical losses which are proportional to the square of the *real power* flow. More precisely, a thermal limit restricts the sum of the squares of *real* and *reactive power*.

Tie-line: The physical connection (e.g. transmission lines, transformers, switch gear, etc.) between two electric systems that permits the transfer of electric energy in one or both directions.

Time Error: An accumulated time difference between Control Area system time and the time standard. Time error is caused by a deviation in Interconnection frequency from 60.0 Hertz.

Time Error Correction: An offset to the Interconnection's scheduled frequency to correct for the time error accumulated on electric clocks.

Transactions: Sales of bulk power via the transmission grid.

Transfer Limit: The maximum amount of power that can be transferred in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions.

Transformer: A device that operates on magnetic principles to increase (step up) or decrease (step down) voltage.

Transient Stability: The ability of an electric system to maintain synchronism between its parts when subjected to a disturbance and to regain a state of equilibrium following that disturbance.

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

Transmission Loading Relief (TLR): A procedure used to manage congestion on the electric transmission system.

Transmission Margin: The difference between the maximum power flow a transmission line can handle and the amount that is currently flowing on the line.

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

Transmission Overload: A state where a transmission line has exceeded either a normal or emergency rating of the electric conductor.

Transmission Owner (TO) or Transmission Provider: Any utility that owns, operates, or controls facilities used for the transmission of electric energy.

Trip: The opening of a circuit breaker or breakers on an electric system, normally to electrically isolate a particular element of the system to prevent it from being damaged by fault current or other potentially damaging conditions. See “Line Trip” for example.

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

Voltage Collapse (decay): An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage Collapse may result in outage of system elements and may include interruption in service to customers.

Voltage Control: The control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

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

Voltage Reduction: A procedure designed to deliberately lower the voltage at a bus. It is often used as a means to reduce demand by lowering the customer’s voltage.

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

Watthour (Wh): A unit of measure of electrical energy equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Appendix G

Transmittal Letters from the Three Working Groups

Mr. James W. Glotfelty
Director, Office of Electric Transmission
and Distribution
U.S. Department of Energy
1000 Independence Avenue SW
Washington, DC 20585

Dr. Nawal Kamel
Special Assistant to the Deputy Minister
Natural Resources Canada
580 Booth Street
Ottawa, ON
K1A 0E4

Dear Mr. Glotfelty and Dr. Kamel:

Enclosed is the Final Report of the Electric System Working Group (ESWG) supporting the United States - Canada Power System Outage Task Force.

This report presents the results of an intensive and thorough investigation by a bi-national team into the causes of the blackout that occurred on August 14, 2003, and recommendations to prevent and reduce the scope of future blackouts. We believe that systematic implementation of these recommendations is critical to maintaining the reliability of bulk power supplies in North America.

The report was written largely by the three co-chairs of the Electric System Working Group (David Meyer, Alison Silverstein, and Tom Rusnov), who also co-chaired the Task Force's Electric System Investigation. They did so with the benefit of extensive input and assistance from many members of the investigation team. Other members of the ESWG reviewed the report in draft and provided valuable suggestions for its improvement. Those members join us in this submittal and have signed on the following page.

Sincerely,

David H. Meyer

David H. Meyer
Senior Advisor
U.S. Department
of Energy
Co-Chair, Electric
System Working Group

Thomas Rusnov
Senior Advisor
Natural Resources
Canada
Co-Chair, Electric
System Working Group

Alison Silverstein

Alison Silverstein
Senior Energy Policy Advisor
to the Chairman
Federal Energy Regulatory
Commission
Co-Chair, Electric
System Working Group

2

Dave Barrie

David Barrie
Senior Vice President
Asset Management
Hydro One Inc.

David Burpee, Director,
Renewable and Electrical Energy Division
Natural Resources Canada

For Donald W. Downes

Donald Downes, Chairman
Connecticut Department of
Public Utility Control

Joseph Eto, Staff Scientist
Lawrence Berkeley National Laboratory
(U.S.), and Consortium for Electric
Reliability Solutions

Jeanne M. Fox

Jeanne Fox, President
New Jersey Board of Public Utilities

H. Kenneth Haase
Senior Vice President, Transmission
New York Power Authority

J. Peter Lark, Chairman
Michigan Public Service Commission

Blaine Loper

Blaine Loper, Senior Engineer
Pennsylvania Public Utility Commission

David McFadden
Chair, National Energy and Infrastructure
Industry Group
Gowlings, Lafleur, Henderson LLP
Ontario

David O'Brien, Commissioner
Vermont Department of Public Service

David O'Connor, Commissioner
Div. of Energy Resources
Massachusetts Office of Consumer Affairs
And Business Regulation

Alan Schriber, Chairman
Ohio Public Utilities Commission

Gene Whitney

Gene Whitney, Policy Analyst
National Science and Technology Council
U.S. Office of Science and Technology
Policy, Executive Office of the President

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001
CHAIRMAN

Canadian Nuclear Safety Commission
President and Chief Executive Officer

Commission canadienne de sûreté nucléaire
Présidente et première dirigeante

February 27, 2004

Mr. James Glotfelty
Director, Office of Electric
Transmission and Distribution
U.S. Department of Energy
1000 Independence Ave., Suite 7B-222
Washington, DC 20585

Dr. Nawal Kamel
Special Assistant to the Deputy Minister
Natural Resources Canada
580 Booth Street
Ottawa, ON
K1A 0E4

Dear Mr. Glotfelty and Dr. Kamel:

Enclosed for incorporation into the Task Force report are revisions to the Interim Report and possible recommendations submitted for consideration by the Nuclear Working Group supporting the United States - Canada Joint Power System Outage Task Force. The members of the Nuclear Working Group join us in this submittal and have signed on the attached pages.

Please provide any comments related to the Canadian nuclear plants to either Mr. Pat Hawley (613-947-3992; hawleyp@cnsc-ccsn.gc.ca) or Mr. Mark Dallaire (613-947-0957; dallairem@cnsc-ccsn.gc.ca). Comments on the U.S. nuclear plants should be directed to either Mr. Cornelius Holden (301-415-3036; cfh@nrc.gov) or Mr. John Boska (301-415-2901; jpb1@nrc.gov).

Sincerely,

Nils J. Diaz
Chairman
U.S. Nuclear Regulatory Commission
U.S. Co-chair, Nuclear Working Group

Linda J. Keen
President and Chief Executive Officer
Canadian Nuclear Safety Commission
Canadian Co-chair, Nuclear Working Group

Enclosures: Nuclear Working Group Signature Pages (2)
Nuclear Working Group Final Report

cc w/encls: Mr. Ian Grant
Director General, Reactor Power Regulation
Canadian Nuclear Safety Commission

Mr. Samuel J. Collins
Deputy Executive Director, Reactor Programs
U.S. Nuclear Regulatory Commission

The members of the Nuclear Working Group hereby submit this report as input to the United States - Canada Joint Power System Outage Task Force:

Nils J. Diaz, Chairman
U.S. Nuclear Regulatory Commission
Co-chair, Nuclear Working Group

Samuel J. Collins, Deputy Executive Director
for Reactor Programs
U.S. Nuclear Regulatory Commission

William D. Magwood, IV, Director, Office of
Nuclear Energy, Science and Technology
U.S. Department of Energy

Edward Wilds, Bureau of Air Management,
Department of Environmental Protection
(Connecticut)

David O'Connor, Commissioner, Division of
Energy Resources, Office of Consumer
Affairs and Business Regulation
(Massachusetts)

J. Peter Lark, Chairman, Public Service
Commission (Michigan)

Frederick F. Butler, Commissioner, New
Jersey Board of Public Utilities (New Jersey)

Paul Eddy, Power Systems Operations
Specialist, Public Service Commission (New
York)

Dr. G. Ivan Maldonado, Associate Professor,
Mechanical, Industrial and Nuclear
Engineering; University of Cincinnati (Ohio)

David J. Allard, CHP, Director, Bureau of
Radiation Protection, Department of
Environmental Protection (Pennsylvania)

David O'Brien, Commissioner
Department of Public Service (Vermont)

The members of the Nuclear Working Group hereby submit this report as input to the United States - Canada Joint Power System Outage Task Force:

Linda J. Keen
President and Chief Executive Officer
Canadian Nuclear Safety Commission
Co-chair, Nuclear Working Group

James Blyth
Director-General, Directorate of Nuclear Substance Regulation
Canadian Nuclear Safety Commission

Ken Pereira
Vice-President, Operations Branch
Canadian Nuclear Safety Commission

Dr. Robert Morrison
Senior Advisor to the Deputy Minister
Natural Resources Canada

Duncan Hawthorne
Chief Executive Officer
Bruce Power
(Representing the Province of Ontario)

Mr. James W. Glotfelty
Director, Office of Electric Transmission
and Distribution
U.S. Department of Energy
1000 Independence Avenue SW
Washington, DC 20585

Dr. Nawal Kamel
Special Assistant to the Deputy Minister
Natural Resources Canada
580 Booth Street
Ottawa, ON
K1A 0E4

Dear Mr. Glotfelty and Dr. Kamel:

Enclosed is the Final Report of the Security Working Group (SWG) supporting the United States - Canada Power System Outage Task Force.

The SWG Final Report presents the results of the Working Group`s analysis of the security aspects of the power outage that occurred on August 14, 2003 and provides recommendations for Task Force consideration on security-related issues in the electricity sector. This report comprises input from public sector, private sector, and academic members of the SWG, with important assistance from many members of the Task Force's investigative team. As co-chairs of the Security Working Group, we represent all members of the SWG in this submittal and have signed below.

Sincerely,

Bob Liscouski
Assistant Secretary for
Infrastructure Protection,
U.S. Department of Homeland Security
Co-Chair, SWG

William J.S. Elliott
Assistant Secretary to the Cabinet,
Security and Intelligence,
Privy Council Office
Government of Canada
Co-Chair, SWG

Attachment 1:

U.S.-Canada Power System Outage Task Force SWG Steering Committee members:

Bob Liscouski, Assistant Secretary for Infrastructure Protection, Department of Homeland Security (U.S. Government) (Co-Chair)

William J.S. Elliott, Assistant Secretary to the Cabinet, Security and Intelligence, Privy Council Office (Government of Canada) (Co-Chair)

U.S. Members

Andy Purdy, Deputy Director, National Cyber Security Division, Department of Homeland Security

Hal Hendershot, Acting Section Chief, Computer Intrusion Section, FBI

Steve Schmidt, Section Chief, Special Technologies and Applications, FBI

Kevin Kolevar, Senior Policy Advisor to the Secretary, DoE

Simon Szykman, Senior Policy Analyst, U.S. Office of Science &Technology Policy, White House

Vincent DeRosa, Deputy Commissioner, Director of Homeland Security (Connecticut)

Richard Swensen, Under-Secretary, Office of Public Safety and Homeland Security (Massachusetts)

Colonel Michael C. McDaniel (Michigan)

Sid Caspersen, Director, Office of Counter-Terrorism (New Jersey)

James McMahon, Senior Advisor (New York)

John Overly, Executive Director, Division of Homeland Security (Ohio)

Arthur Stephens, Deputy Secretary for Information Technology, (Pennsylvania)

Kerry L. Sleeper, Commissioner, Public Safety (Vermont)

Canada Members

James Harlick, Assistant Deputy Minister, Office of Critical Infrastructure Protection and Emergency Preparedness

Michael Devaney, Deputy Chief, Information Technology Security Communications Security Establishment

Peter MacAulay, Officer, Technological Crime Branch of the Royal Canadian Mounted Police

Gary Anderson, Chief, Counter-Intelligence – Global, Canadian Security Intelligence Service

Dr. James Young, Commissioner of Public Security, Ontario Ministry of Public Safety and Security