I. Conclusions and Recommendations

A. General Conclusions

The August 14 blackout had many similarities with previous large-scale blackouts, including the 1965 Northeast blackout that was the basis for forming NERC in 1968, and the July 1996 outages in the West. Common factors include: conductor contacts with trees, inability of system operators to visualize events on the system, failure to operate within known safe limits, ineffective operational communications and coordination, inadequate training of operators to recognize and respond to system emergencies, and inadequate reactive power resources.

The general conclusions of the NERC investigation are as follows:

- Several entities violated NERC operating policies and planning standards, and those violations contributed directly to the start of the cascading blackout.
- The approach used to monitor and ensure compliance with NERC and regional reliability standards was 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.
- 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.
- Deficiencies identified in studies of prior large-scale blackouts were repeated, including poor vegetation management, operator training practices, and a lack of adequate tools that allow operators to visualize system conditions.

B. Causal Analysis Results

This section summarizes the causes of the blackout. Investigators found that the Sammis-Star 345-kV line trip was a seminal event, after which power system failures began to spread beyond northeastern Ohio to affect other areas. After the Sammis-Star line outage at 16:05:57, the accelerating cascade of line and generator outages would have been difficult or impossible to stop with installed protection and controls. Therefore, the causes of the blackout are focused on problems that occurred before the Sammis-Star outage.

The causes of the blackout described here did not result from inanimate events, such as “the alarm processor failed” or “a tree contacted a power line.” Rather, the causes of the blackout were rooted in deficiencies resulting from decisions, actions, and the failure to act of the individuals, groups, and organizations involved. These causes were preventable prior to August 14 and are correctable. Simply put — blaming a tree for contacting a line serves no useful purpose. The responsibility lies with the organizations and persons charged with establishing and implementing an effective vegetation management program to maintain safe clearances between vegetation and energized conductors.

Each cause identified here was verified to have existed on August 14 prior to the blackout. Each cause was also determined to be both a necessary condition to the blackout occurring and, in conjunction with the other causes, sufficient to cause the blackout. In other words, each cause was a direct link in the causal chain leading to the blackout and the absence of any one of these causes could have broken that chain and prevented the blackout. This definition distinguishes causes as a subset of a broader category of identified deficiencies. Other deficiencies are noted in the next section; they may have been contributing factors leading to the blackout or may present serious reliability concerns completely unrelated to the blackout, but they were not deemed by the investigators to be direct causes of the blackout. They are still important; however, because they might have caused a blackout under a different set of circumstances.

1. Causes of the Blackout

Group 1 Causes: FE lacked situational awareness of line outages and degraded conditions on the FE system. The first five causes listed below collectively resulted in a lack of awareness by the FE system operators that line outages were occurring on the FE system and that operating limit violations existed after the trip of the Chamberlin-Harding line at 15:05 and worsened with subsequent line trips. This lack of situational awareness precluded the FE system operators from taking corrective actions to return the system to within limits, and from notifying MISO and neighboring systems of the degraded system conditions and loss of critical functionality in the control center.

> ***Cause 1a: FE had no alarm failure detection system.*** Although the FE alarm processor stopped functioning properly at 14:14, the computer support staff remained unaware of this failure until the second EMS server failed at 14:54, some 40 minutes later. Even at 14:54, the responding support staff understood only that all of the functions normally hosted by server H4 had failed, and did not realize that the alarm processor had failed 40 minutes earlier. Because FE had no periodic diagnostics to evaluate and report the state of the alarm processor, nothing about the eventual failure of two EMS servers would have directly alerted the support staff that the alarms had failed in an infinite loop lockup — or that the alarm processor had failed in this manner both earlier and independently of the server failure events. Even if the FE computer support staff had communicated the EMS failure to the operators (which they did not) and fully tested the critical functions after restoring the EMS (which they did not), there still would have been a minimum of 40 minutes, from 14:14 to 14:54, during which the support staff was unaware of the alarm processor failure.

> ***Cause 1b: FE computer support staff did not effectively communicate the loss of alarm functionality to the FE system operators after the alarm processor failed at 14:14, nor did they have a formal procedure to do so.*** Knowing the alarm processor had failed would have provided FE operators the opportunity to detect the Chamberlin-Harding line outage shortly after 15:05 using supervisory displays still available in their energy management system. Knowledge of the Chamberlin-Harding line outage would have enabled FE operators to recognize worsening conditions on the FE system and to consider manually reclosing the Chamberlin-Harding line as an emergency action after subsequent outages of the Hanna-Juniper and Star-South Canton 345-kV lines. Knowledge of the alarm processor failure would have allowed the FE operators to be more receptive to information being received from MISO and neighboring systems regarding degrading conditions on the FE system. This knowledge would also have allowed FE operators to warn MISO and neighboring systems of the loss of a critical monitoring function in the FE control center computers, putting them on alert to more closely monitor conditions on the FE system, although there is not a specific procedure requiring FE to warn MISO of a loss of a critical control center function. The FE operators were complicit in this deficiency by not recognizing the alarm processor failure existed, although no new alarms were received by the operators after 14:14. A period of more than 90

minutes elapsed before the operators began to suspect a loss of the alarm processor, a period in which, on a typical day, scores of routine alarms would be expected to print to the alarm logger.

Cause 1c: FE control center computer support staff did not fully test the functionality of applications, including the alarm processor, after a server failover and restore. After the FE computer support staff conducted a warm reboot of the energy management system to get the failed servers operating again, they did not conduct a sufficiently rigorous test of critical energy management system applications to determine that the alarm processor failure still existed. Full testing of all critical energy management functions after restoring the servers would have detected the alarm processor failure as early as 15:08 and would have cued the FE system operators to use an alternate means to monitor system conditions. Knowledge that the alarm processor was still failed after the server was restored would have enabled FE operators to proactively monitor system conditions, become aware of the line outages occurring on the system, and act on operational information that was received. Knowledge of the alarm processor failure would also have allowed FE operators to warn MISO and neighboring systems, assuming there was a procedure to do so, of the loss of a critical monitoring function in the FE control center computers, putting them on alert to more closely monitor conditions on the FE system.

Cause 1d: FE operators did not have an effective alternative to easily visualize the overall conditions of the system once the alarm processor failed. An alternative means of readily visualizing overall system conditions, including the status of critical facilities, would have enabled FE operators to become aware of forced line outages in a timely manner even though the alarms were non-functional. Typically, a dynamic map board or other type of display could provide a system status overview for quick and easy recognition by the operators. As with the prior causes, this deficiency precluded FE operators from detecting the degrading system conditions, taking corrective actions, and alerting MISO and neighboring systems.

Cause 1e: FE did not have an effective contingency analysis capability cycling periodically on-line and did not have a practice of running contingency analysis manually as an effective alternative for identifying contingency limit violations. Real-time contingency analysis, cycling automatically every 5–15 minutes, would have alerted the FE operators to degraded system conditions following the loss of the Eastlake 5 generating unit and the Chamberlin-Harding 345-kV line. Initiating a manual contingency analysis after the trip of the Chamberlin-Harding line could also have identified the degraded system conditions for the FE operators. Knowledge of a contingency limit violation after the loss of Chamberlin-Harding and knowledge that conditions continued to worsen with the subsequent line losses would have allowed the FE operators to take corrective actions and notify MISO and neighboring systems of the developing system emergency. FE was operating after the trip of the Chamberlin-Harding 345-kV line at 15:05, such that the loss of the Perry 1 nuclear unit would have caused one or more lines to exceed their emergency ratings.

Group 2 Cause: FE did not effectively manage vegetation in its transmission rights-of-way.

Cause 2: FE did not effectively manage vegetation in its transmission line rights-of-way. The lack of situational awareness resulting from Causes 1a–1e would have allowed a number of system failure modes to go undetected. However, it was the fact that FE allowed trees growing in its 345-kV transmission rights-of-way to encroach within the minimum safe clearances from energized conductors that caused the Chamberlin-Harding, Hanna-Juniper, and Star-South Canton 345-kV line outages. These three tree-related outages triggered the localized cascade of the Cleveland-Akron 138-kV system and the overloading and tripping of the Sammis-Star line, eventually snowballing into an uncontrolled wide-area cascade. These three lines experienced non-random, common mode failures due to unchecked tree growth. With properly cleared rights-of-way and calm weather, such as existed in Ohio on August 14, the chances of those three lines randomly tripping within 30 minutes is extremely small. Effective vegetation management practices would have avoided this particular sequence of line outages that triggered the blackout. However, effective vegetation management might not have precluded other latent failure modes. For example, investigators determined that there was an elevated risk of a voltage collapse in the Cleveland-Akron area on August 14 if the Perry 1 nuclear plant had tripped that afternoon in addition to Eastlake 5, because the transmission system in the Cleveland-Akron area was being operated with low bus voltages and insufficient reactive power margins to remain stable following the loss of Perry 1.

Group 3 Causes: Reliability coordinators did not provide effective diagnostic support.

Cause 3a: MISO was using non-real-time information to monitor real-time operations in its area of responsibility. MISO was using its Flowgate Monitoring Tool (FMT) as an alternative method of observing the real-time status of critical facilities within its area of responsibility. However, the FMT was receiving information on facility outages from the NERC SDX, which is not intended as a real-time information system and is not required to be updated in real-time. Therefore, without real-time outage information, the MISO FMT was unable to accurately estimate real-time conditions within the MISO area of responsibility. If the FMT had received accurate line outage distribution factors representing current system topology, it would have identified a contingency overload on the Star-Juniper 345-kV line for the loss of the Hanna-Juniper 345-kV line as early as 15:10. This information would have enabled MISO to alert FE operators regarding the contingency violation and would have allowed corrective actions by FE and MISO. The reliance on non-real-time facility status information from the NERC SDX is not limited to MISO; others in the Eastern Interconnection use the same SDX information to calculate TLR curtailments in the IDC and make operational decisions on that basis. What was unique compared to other reliability coordinators on that day was MISO's reliance on the SDX for what they intended to be a real-time system monitoring tool.

Cause 3b: MISO did not have real-time topology information for critical lines mapped into its state estimator. The MISO state estimator and network analysis tools were still considered to be in development on August 14 and were not fully capable of automatically recognizing changes in the configuration of the modeled system. Following the trip of lines in the Cinergy system at 12:12 and the DP&L Stuart-Atlanta line at 14:02, the MISO state estimator failed to solve correctly as a result of large numerical mismatches. MISO real-time contingency analysis, which operates only if the state estimator solves, did not operate properly in automatic mode again until after the blackout. Without real-time contingency analysis information, the MISO operators did not detect that the FE system was in a contingency violation after the Chamberlin-Harding 345-kV line tripped at 15:05. Since MISO was not aware of the contingency violation, MISO did not inform FE and thus FE's lack of situational awareness described in Causes 1a-e was allowed to continue. With an operational state estimator and real-time contingency analysis, MISO operators would have known of the contingency violation and could have informed FE, thus enabling FE and MISO to take timely actions to return the system to within limits.

Cause 3c: The PJM and MISO reliability coordinators lacked an effective procedure on when and how to coordinate an operating limit violation observed by one of them in the other's area due to a contingency near their common boundary. The lack of such a procedure caused ineffective communications between PJM and MISO regarding PJM's awareness of a possible overload on the Sammis-Star line as early as 15:48. An effective procedure would have enabled PJM to more clearly communicate the information it had regarding limit violations on the FE system, and would have enabled MISO to be aware of those conditions and initiate corrective actions with FE.

C. Other Deficiencies

The deficiencies listed above were determined by investigators to be necessary and sufficient to cause the August 14 blackout — therefore they are labeled causes. Investigators identified many other deficiencies, which did not meet the “necessary and sufficient” test, and therefore were not labeled as causes of the blackout. In other words, a sufficient set of deficiencies already existed to cause the blackout without these other deficiencies.

However, these other deficiencies represent significant conclusions of the investigation, as many of them aggravated the enabling conditions or the severity of the consequences of the blackout. An example is the ninth deficiency listed below, regarding poor communications within the FE control center. Poor communications within the control center did not cause the blackout and the absence of those poor communications within the FE control center would not have prevented the blackout. However, poor communications in the control center was a contributing factor, because it increased the state of confusion in the control center and exacerbated the FE operators’ lack of situational awareness. The investigators also discovered a few of these deficiencies to be unrelated to the blackout but still of significant concern to system reliability. An example is deficiency number eight: FE was operating close to a voltage collapse in the Cleveland-Akron area, although voltage collapse did not initiate the sequence of events that led to the blackout.

1. Summary of Other Deficiencies Identified in the Blackout Investigation

1. **The NERC and ECAR compliance programs did not identify and resolve specific compliance violations before those violations led to a cascading blackout.** Several entities in the ECAR region violated NERC operating policies and planning standards, and those violations contributed directly to the start of the cascading blackout. Had those violations not occurred, the blackout would not have occurred. The approach used for monitoring and assuring compliance with NERC and regional reliability standards prior to August 14 delegated much of the responsibility and accountability to the regional level. Due to confidentiality considerations, NERC did not receive detailed information about violations of specific parties prior to August 14. This approach meant that the NERC compliance program was only as effective as that of the weakest regional reliability council.
2. **There are no commonly accepted criteria that specifically address safe clearances of vegetation from energized conductors.** The National Electrical Safety Code specifies in detail criteria for clearances from several classes of obstructions, including grounded objects. However, criteria for vegetation clearances vary by state and province, and by individual utility.
3. **Problems identified in studies of prior large-scale blackouts were repeated on August 14, including deficiencies in vegetation management, operator training, and tools to help operators better visualize system conditions.** Although these issues had been previously reported, NERC and some regions did not have a systematic approach to tracking successful implementation of those prior recommendations.
4. **Reliability coordinators and control areas have adopted differing interpretations of the functions, responsibilities, authorities, and capabilities needed to operate a reliable power system.** For example, MISO delegated substantial portions of its reliability oversight functions to its member control areas and did not provide a redundant set of eyes adequate for monitoring a wide-area view of reliability in its area of responsibility. Further, NERC operating policies do not specify what tools are specifically required of control areas and reliability coordinators, such as state estimation and network analysis tools, although the policies do specify the expected outcomes of analysis.

5. **In ECAR, data used to model loads and generators were inaccurate due to a lack of verification through benchmarking with actual system data and field testing.** Inaccuracies in load models and other system modeling data frustrated investigators trying to develop accurate simulations of the events on August 14. Inaccurate model data introduces potential errors in planning and operating models. Further, the lack of synchronized data recorders made the reconstruction of the sequence of events very difficult.

6. **In ECAR, planning studies, design assumptions, and facilities ratings were not consistently shared and were not subject to adequate peer review among operating entities and regions.** As a result, systems were studied and analyzed in "silos" and study assumptions and results were not always understood by neighboring systems, although those assumptions affected those other systems.

7. **Available system protection technologies were not consistently applied to optimize the ability to slow or stop an uncontrolled cascading failure of the power system.** The effects of zone 3 relays, the lack of under-voltage load shedding, and the coordination of underfrequency load shedding and generator protection are all areas requiring further investigation to determine if opportunities exist to limit or slow the spread of a cascading failure of the system.

8. **FE was operating its system with voltages below critical voltages and with inadequate reactive reserve margins.** FE did not retain and apply knowledge from earlier system studies concerning voltage collapse concerns in the Cleveland-Akron area. Conventional voltage studies done by FE to assess normal and abnormal voltage ranges and percent voltage decline did not accurately determine an adequate margin between post-contingency voltage and the voltage collapse threshold at various locations in their system. If FE had conducted voltage stability analyses using well-established P-V and Q-V techniques, FE would have detected insufficient dynamic reactive reserves at various locations in their system for the August 14 operating scenario that includes the Eastlake 5 outage. Additionally, FE's stated acceptable ranges for voltage are not compatible with neighboring systems or interconnected systems in general. FE was operating in apparent violation of its own historical planning and operating criteria that were developed and used by Centerior Energy Corporation (The Cleveland Electric Illuminating Company and the Toledo Edison Company) prior to 1998 to meet the relevant NERC and ECAR standards and criteria. In 1999, FE reduced its operating voltage lower limits in the Cleveland-Akron area compared to those criteria used in prior years. These reduced minimum operating voltage limits were disclosed in FE's 1999–2003 Planning & Operating Criteria Form 715 submittal to FERC, but were not challenged at the time.

9. **FE did not have an effective protocol for sharing operator information within the control room and with others outside the control room.** FE did not have an effective plan for communications in the control center during a system emergency. Communications within the control center and with others outside the control center were confusing and hectic. The communications were not effective in helping the operators focus on the most urgent problem in front of them — the emerging system and computer failures.

10. **FE did not have an effective generation redispatch plan and did not have sufficient redispatch resources to relieve overloaded transmission lines supplying northeastern Ohio.** Following the loss of the Chamberlin-Harding 345-kV line, FE had a contingency limit violation but did not have resources available for redispatch to effectively reduce the contingency overload within 30 minutes.

11. **FE did not have an effective load reduction plan and did not have an adequate load reduction capability, whether automatic or manual, to relieve overloaded transmission lines**

supplying northeastern Ohio. A system operator is required to have adequate resources to restore the system to a secure condition within 30 minutes or less of a contingency. Analysis shows that shedding 2,000 MW of load in the Cleveland-Akron area after the loss of the Star-South Canton 345-kV line or shedding 2,500 after the West Akron Substation 138-kV bus failure could have halted the cascade in the northeastern Ohio area.

12. **FE did not adequately train its operators to recognize and respond to system emergencies, such as multiple contingencies.** The FE operators did not recognize the information they were receiving as clear indications of an emerging system emergency. Even when the operators grasped the idea that their computer systems had failed and the system was in trouble, the operators did not formally declare a system emergency and inform MISO and neighboring systems.

13. **FE did not have the ability to transfer control of its power system to an alternate center or authority during system emergencies.** FE had not arranged for a backup control center or backup system control and monitoring functions. A typical criterion would include the need to evacuate the control center due to fire or natural disaster. Although control center evacuation was not required on August 14, FE had an equivalent situation with the loss of its critical monitoring and control functionality in the control center.

14. **FE operational planning and system planning studies were not sufficiently comprehensive to ensure reliability because they did not include a full range of sensitivity studies based on the 2003 Summer Base Case.** A comprehensive range of planning studies would have involved analyses of all operating scenarios likely to be encountered, including those for unusual operating conditions and potential disturbance scenarios.

15. **FE did not perform adequate hour-ahead operations planning studies after Eastlake 5 tripped off-line at 13:31 to ensure that FE could maintain a 30-minute response capability for the next contingency.** The FE system was not within single contingency limits from 15:06 to 16:06. In addition to day-ahead planning, the system should have been restudied after the forced outage of Eastlake 5.

16. **FE did not perform adequate day-ahead operations planning studies to ensure that FE had adequate resources to return the system to within contingency limits following the possible loss of their largest unit, Perry 1.** After Eastlake 4 was forced out on August 13, the operational plan was not modified for the possible loss of the largest generating unit, Perry 1.

17. **FE did not have or use specific criteria for declaring a system emergency.**

18. **ECAR and MISO did not precisely define "critical facilities" such that the 345-kV lines in FE that caused a major cascading failure would have to be identified as critical facilities for MISO.** MISO's procedure in effect on August 14 was to request FE to identify critical facilities on its system to MISO.

19. **MISO did not have additional monitoring tools that provided high-level visualization of the system.** A high-level monitoring tool, such as a dynamic map board, would have enabled MISO operators to view degrading conditions in the FE system.

20. **ECAR and its member companies did not adequately follow ECAR Document 1 to conduct regional and interregional system planning studies and assessments.** This would have

enabled FE to further develop specific operating limits of their critical interfaces by assessing the effects of power imports and exports, and regional and interregional power transfers.

21. **ECAR did not have a coordinated procedure to develop and periodically review reactive power margins.** This would have enabled all member companies to establish maximum power transfer levels and minimum operating voltages to respect these reactive margins.

22. **Operating entities and reliability coordinators demonstrated an over-reliance on the administrative levels of the TLR procedure to remove contingency and actual overloads, when emergency redispatch of other emergency actions were necessary.** TLR is a market-based congestion relief procedure and is not intended for removing an actual violation in real-time.

23. **Numerous control areas in the Eastern Interconnection, including FE, were not correctly tagging dynamic schedules, resulting in large mismatches between actual, scheduled, and tagged interchange on August 14.** This prevented reliability coordinators in the Eastern Interconnection from predicting and modeling the effects of these transactions on the grid.

D. Blackout Recommendations

1. NERC Recommendations Approved February 10, 2004

On February 10, 2004, the NERC Board of Trustees approved 14 recommendations offered by the NERC Steering Group to address the causes of the August 14 blackout and other deficiencies. These recommendations remain valid and applicable to the conclusions of this final report. The recommendations fall into three categories:

Actions to Remedy Specific Deficiencies: Specific actions directed to FE, MISO, and PJM to correct the deficiencies that led to the blackout.

- 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.

- Strengthen the NERC Compliance Enforcement Program.
- Initiate control area and reliability coordinator reliability readiness audits.
- Evaluate vegetation management procedures and results.
- Establish a program to track implementation of recommendations.

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

- Improve operator and reliability coordinator training.
- Evaluate reactive power and voltage control practices.
- Improve system protection to slow or limit the spread of future cascading outages.

- Clarify reliability coordinator and control area functions, responsibilities, capabilities, and authorities.
- Establish guidelines for real-time operating tools.
- Evaluate lessons learned during system restoration.
- Install additional time-synchronized recording devices as needed.
- Reevaluate system design, planning, and operating criteria.
- Improve system modeling data and data exchange practices.

2. U.S.-Canada Power System Outage Task Force Recommendations

On April 5, 2004, the U.S.-Canada Power System Outage Task Force issued its final report of the August 14 blackout containing its 46 recommendations. The recommendations were grouped into four areas:

Group 1: Institutional Issues Related to Reliability (Recommendations 1–14)

Group 2: Support and Strengthen NERC's Actions of February 10, 2004 (Recommendations 15–31)

Group 3: Physical and Cyber Security of North American Bulk Power Systems (Recommendations 32–44)

Group 4: Canadian Nuclear Power Sector (Recommendations 45–46)

The investigation team is encouraged by the recommendations of the Task Force and believes these recommendations are consistent with the conclusions of the NERC investigation. Although the NERC investigation has focused on a technical analysis of the blackout, the policy recommendations in Group 1 appear to support many of NERC's findings regarding the need for legislation for enforcement of mandatory reliability standards. In other recommendations, the Task Force seeks to strengthen compliance enforcement and other NERC functions by advancing reliability policies at the federal, state, and provincial levels.

The second group of Task Force recommendations builds upon the original fourteen NERC recommendations approved in February 2004. NERC has considered these expanded recommendations, is implementing these recommendations where appropriate, and will inform the Task Force if additional considerations make any recommendation inappropriate or impractical.

The third group of Task Force recommendations addresses critical infrastructure protection issues. NERC agrees with the conclusions of the Task Force (Final Task Force report, page 132) that there is "no evidence that a malicious cyber attack was a direct or indirect cause of the August 14, 2003, power outage." The recommendations of the Task Force report are forward-looking and address issues that should be considered, whether or not there had been a blackout on August 14. NERC has assigned its Critical Infrastructure Protection Committee to evaluate these recommendations and report what actions, if any, NERC should take to implement those recommendations.

The fourth group of recommendations is specific to Canadian nuclear facilities and is outside the scope of NERC responsibilities.

Additional NERC Recommendations

While the ongoing NERC investigation has confirmed the validity of the original fourteen NERC recommendations and the NERC Steering Group concurs with the Task Force's recommendations, four additional NERC recommendations resulted from further investigation since February and in consideration of the Task Force final report. The additional NERC recommendations are as follows:

Recommendation 4d — Develop a standard on vegetation clearances.

The Planning Committee, working with the Standards Authorization Committee, shall develop a measurable standard that specifies the minimum clearances between energized high voltage lines and vegetation. Appropriate criteria from the National Electrical Safety Code, or other appropriate code, should be adapted and interpreted so as to be applicable to vegetation.

Recommendation 15 — Develop a standing capability for NERC to investigate future blackouts and disturbances.

NERC shall develop and be prepared to implement a NERC standing procedure for investigating future blackouts and system disturbances. Many of the methods, tools, and lessons from the investigation of the August 14 blackout are appropriate for adoption.

Recommendation 16 — Accelerate the standards transition.

NERC shall accelerate the transition from existing operating policies, planning standards, and compliance templates to a clear and measurable set of reliability standards. (This recommendation is consistent with the Task Force recommendation 25.)

Recommendation 17 — Evaluate NERC actions in the areas of cyber and physical security

The Critical Infrastructure Protection Committee shall evaluate the U.S.-Canada Power System Outage Task Force's Group III recommendations to determine if any actions are needed by NERC and report a proposed action plan to the board.

Action Plan

NERC will develop a mechanism to track all of the NERC, Task Force, and other reliability recommendations resulting from subsequent investigations of system disturbances and compliance reviews. Details of that plan are outside the scope of this report.

3. Complete Set of NERC Recommendations

This section consolidates all NERC recommendations, including the initial 14 recommendations approved in February 2004 and the four additional recommendations described above, into a single place.

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

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 has taken immediate actions to ensure that the 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.

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 will issue a final report of those violations once the investigation is complete.

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. 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 2a: Each regional reliability council shall report to the NERC Compliance Enforcement Program within one month of occurrence all significant 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: When 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.

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.

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 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, like the one that occurred 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 incurs a substantial ongoing cost in many areas of North America. However, it is an important investment for assuring a reliable electric system. 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.

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 on measuring performance as indicated by the number of high-voltage line trips caused by vegetation. 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 transmission line trips resulting from vegetation contact. The program will use the successful WECC vegetation monitoring program as a model.

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.

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.

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. 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.

(NEW) Recommendation 4d: The Planning Committee, working with the Standards Authorization Committee, shall develop a measurable standard that specifies the minimum clearances between energized high voltage lines and vegetation. Appropriate criteria from the National Electrical Safety Code, or other appropriate code, should be adapted and interpreted so as to be applicable to vegetation.

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

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.

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

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, and not rely mainly on learning from and reacting to catastrophic failures.

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.

Recommendation 6: Improve Operator and Reliability Coordinator Training.

The investigation found 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, 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.

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.

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 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.

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 reactive power and voltage control deficiencies noted on August 14 are also symptomatic of a systematic breakdown of the reliability studies and practices in FE and the ECAR region. As a result, unsafe voltage criteria were 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 500 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 five 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, many 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. 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.

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

A second key conclusion 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 underfrequency load shedding and its coordination with generator under and over-frequency protection and controls.

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 TLR procedure is not intended to be used as a method for restoring the system from an actual Operating Security Limit violation to a secure operating state.

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 the FE 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 failure execution, monitoring external facilities, solution quality, post-contingency automatic actions, rates including mean/maximum times between failures, reporting of results, presentation of solution results including alarms, and troubleshooting procedures including procedures for investigating non-converging contingency studies.

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 blackstart 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 Eastlake 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 interregional basis as needed for reliable system planning and operation.

(NEW) Recommendation 15: Develop a standing capability for NERC to investigate future blackouts and disturbances.

NERC shall develop and be prepared to implement a NERC standing procedure for investigating future blackouts and system disturbances. Many of the methods, tools, and lessons from the investigation of the August 14 blackout are appropriate for adoption.

(NEW) Recommendation 16: Accelerate the standards transition.

NERC shall accelerate the transition from existing operating policies, planning standards, and compliance templates to a clear and measurable set of reliability standards. (This recommendation is consistent with the Task Force recommendation 25).

(NEW) Recommendation 17 — Evaluate NERC actions in the areas of cyber and physical security.

The Critical Infrastructure Protection Committee shall evaluate the U.S.-Canada Power System Outage Task Force's Group III recommendations to determine if any actions are needed by NERC and report a proposed action plan to the board.

4. Specific Actions Directed to FE, MISO, and PJM

Corrective Actions to be Completed by FirstEnergy

FE shall complete the following corrective actions by June 30, 2004. Unless otherwise stated, the requirements apply to the FE northern Ohio system and connected generators.

1. Voltage Criteria and Reactive Resources

a. **Interim Voltage Criteria.** The investigation team found that FE was not operating on August 14 within NERC planning and operating criteria with respect to its voltage profile and reactive power supply margin in the Cleveland-Akron area. FE was also operating outside its own historical planning and operating criteria that were developed and used by Centerior Energy Corporation (The Cleveland Electric Illuminating Company and the Toledo Edison Company) prior to 1998 to meet the relevant NERC and ECAR standards and criteria. FE stated acceptable ranges for voltage are not compatible with neighboring systems or interconnected systems in general.

Until such time that the study of the northern Ohio system ordered by the Federal Energy Regulatory Commission (FERC) on December 23 is completed, and until FE is able to determine (in b. below) a current set of voltage and reactive requirements verified to be within NERC and ECAR criteria, FE shall immediately operate such that voltages at all 345-kV buses in the Cleveland-Akron area shall have a minimum voltage of .95 per unit following the simultaneous loss of the two largest generating units in that area.

b. **Calculation of Minimum Bus Voltages and Reactive Reserves.** FE shall, consistent with or as part of the FERC-ordered study, determine the minimum location-specific voltages at all 345-kV and 138-kV buses and all generating stations within their control area (including merchant plants). FE shall determine the minimum dynamic reactive reserves that must be maintained in local areas to ensure that these minimum voltages are met following contingencies studied in accordance with ECAR Document 1. Criteria and minimum voltage requirements must comply with NERC planning criteria, including Table 1A, Category C3, and Operating Policy 2.

c. **Voltage Procedures.** FE shall determine voltage and reactive criteria and procedures to enable operators to understand and operate these criteria.

d. **Study Results.** When the FERC-ordered study is completed, FE is to adopt the planning and operating criteria determined as a result of that study and update the operating criteria and procedures for its system operators. If the study indicates a need for system reinforcements, FE shall develop a plan for developing such reinforcements as soon as practical, and shall develop operational procedures or other mitigating programs to maintain safe operating conditions until such time that the necessary system reinforcements can be made.

e. **Reactive Resources.** FE shall inspect all reactive resources, including generators, and assure that all are fully operational. FE shall verify that all installed capacitors have no blown fuses and that at least 98 percent of installed capacitors at 69-kV and higher are available and in service during the summer 2004.

f. **Communications.** FE shall communicate its voltage criteria and procedures, as described in the items above to MISO and FE neighboring systems.

2. Operational Preparedness and Action Plan

The FE 2003 Summer Assessment was not considered to be sufficiently comprehensive to cover a wide range of known and expected system conditions, nor effective for the August 14 conditions based on the following:

- No voltage stability assessment was included to assess the Cleveland-Akron area which has a long-known history of potential voltage collapse, as indicated CEI studies prior to 1997, by non-convergence of power flow studies in the 1998 analysis, and advice from AEP of potential voltage collapse prior to the onset of the 2003 summer load period.
- Only single contingencies were tested for basically one set of 2003 study conditions. This does not comply with the study requirements of ECAR Document 1.
- Study conditions should have assumed a wider range of generation dispatch and import/export and interregional transfers. For example, imports from MECS (north-to-south transfers) are likely to be less stressful to the FE system than imports from AEP (south-to-north transfers). Sensitivity studies should have been conducted to assess the impact of each key parameter and derive the system operating limits accordingly based on the most limiting of transient stability, voltage stability, and thermal capability.
- The 2003 study conditions are considered to be more onerous than those assumed in the 1998 study, since the former has Davis Besse (830 MW) as a scheduled outage. However, the 2003 study does not show any voltage instability problems as shown by the 1998 study.
- The 2003 study conditions are far less onerous than the actual August 14 conditions from the generation and transmission availability viewpoint. This is another indication that n-1 contingency assessment, based on one assumed system condition, is not sufficient to cover the variability of changing system conditions due to forced outages.

FE shall prepare and submit to ECAR, with a copy to NERC, an Operational Preparedness and Action Plan to ensure system security and full compliance with NERC and [regional] planning and operating criteria, including ECAR Document 1. The action plan shall include, but not be limited to the following:

a. **2004 Summer Studies.** Complete a 2004 summer study to identify a comprehensive set of System Operating Limits (OSL) and Interconnection Reliability Limits (IRLs) based on the NERC Operating Limit Definition Task Force Report. Any inter-dependency between FE OSL and those of its neighboring entities, known and forecasted regional and interregional transfers, shall be included in the derivation of OSL and IRL.

b. **Extreme Contingencies.** Identify high-risk contingencies that are beyond normal studied criteria and determine the performance of the system for these contingencies. Where these extreme contingencies result in cascading outages, determine means to reduce their probability of occurrence or impact. These contingencies and mitigation plans must be communicated to FE operators, ECAR, MISO, and neighboring systems.

c. **Maximum Import Capability.** Determine the maximum import capability into the Cleveland-Akron area for the summer of 2004, consistent with the criteria stated in (1) above and all applicable NERC and ECAR criteria. The maximum import capability shall take into account historical and forecasted transactions and outage conditions expected with due regard to maintaining adequate operating and local dynamic reactive reserves.

d. **Vegetation Management.** FE was found to not be complying with its own procedures for rights-of-way maintenance and was not adequately resolving inspection and forced outage reports indicating persistent problems with vegetation contacts prior to August 14, 2003. FE shall complete rights-of-way trimming for all 345-kV and 138-kV transmission lines, so as to be in compliance with the National Electrical Safety Code criteria for safe clearances for overhead conductors, other applicable federal, state and local laws, and FE rights-of-way maintenance procedures. Priority should be placed on completing work for all 345-kV lines as soon as possible. FE will report monthly progress to NERC and ECAR.

e. **Line Ratings.** FE shall reevaluate its criteria for calculating line ratings, survey the 345-kV, and 138-kV rights-of-way by visual inspection to ensure line ratings are appropriate for the clearances observed, and calculate updated ratings for each line. FE shall ensure that system operators, MISO, ECAR, NERC (MMWG), and neighboring systems are informed of and able to use the updated line ratings.

3. Emergency Response Capabilities and Preparedness

a. **Emergency Response Resources.** FE shall develop a capability, no later than June 30, 2004, to reduce load in the Cleveland-Akron area by 1,500 MW within ten minutes of a directive to do so by MISO or the FE system operator. Such a capability may be provided by automatic or manual load shedding, voltage reduction, direct-controlled commercial or residential load management, or any other method or combination of methods capable of achieving the 1,500 MW of reduction in ten minutes without adversely affecting other interconnected systems. The amount of required load reduction capability may be reduced to an amount shown by the FERC-ordered study to be sufficient for response to severe contingencies <u>and</u> if approved by ECAR and NERC.

b. **Emergency Response Plan.** FE shall develop emergency response plans, including plans to deploy the load reduction capabilities noted above. The plan shall include criteria for declaring an emergency and various states of emergency. The plan shall include detailed descriptions of authorities, operating procedures, and communication protocols with all the relevant entities including MISO, FE operators, and market participants within the FE area that have the ability to move generation or shed load upon orders from FE operators. The plan shall include procedures for load restoration after the declaration that the FE system is no longer in the emergency operating state.

4. Operating Center and Training

a. **Operator Communications.** FE shall develop communications procedures for FE operating personnel to use within FE, with MISO and neighboring systems, and others. The procedure and the operating environment within the FE system control center shall allow focus on reliable system operation and avoid distractions such as calls from customers and others who are not responsible for operation of a portion of the transmission system.

b. **Reliability Monitoring Tools.** FE shall ensure its state estimation and real-time contingency analysis functions are being used to reliably execute full contingency analysis automatically every ten minutes, or on demand, and to alarm operators of potential first contingency violations.

c. **System Visualization Tools.** FE shall provide its operating personnel with the capability to visualize the status of the power system from an overview perspective and to determine critical system failures or unsafe conditions quickly without multiple-step searches for failures. A dynamic map board or equivalent capability is encouraged.

d. **Backup Functions and Center.** FE shall develop and prepare to implement a plan for the loss of its system operating center or any portion of its critical operating functions. FE shall comport with the criteria of the NERC Reference Document — Back Up Control Centers, and ensure that FE is able to continue meeting all NERC and ECAR criteria in the event the operating center becomes unavailable. Consideration should be given to using capabilities at MISO or neighboring systems as a backup capability, at least for summer 2004, until alternative backup functionality can be provided.

e. **GE XA21 System Updates.** Until the current energy management system is replaced, FE shall incorporate all fixes for the GE XA21 system known to be necessary to assure reliable and stable operation of critical reliability functions, and particularly to correct the alarm processor failure that occurred on August 14, 2003.

f. **Operator Training.** Prior to June 30, 2004, FE shall meet the operator training requirements detailed in NERC Recommendation 6.

g. **Technical Support.** FE shall develop and implement a written procedure describing the interactions between control center technical support personnel and system operators. The procedure shall address notification of loss of critical functionality and testing procedures.

5. Corrective Actions to be Completed by MISO

MISO shall complete the following corrective actions no later than June 30, 2004.

1. **Reliability Tools.** MISO shall fully implement and test its topology processor to provide its operating personnel real-time view of the system status for all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems. Alarms should be provided for operators for all critical transmission line outages. MISO shall establish a means of exchanging outage information with its members and neighboring systems such that the MISO state estimation has accurate and timely information to perform as designed. MISO shall fully implement and test its state estimation and real-time contingency analysis tools to ensure they can operate reliably no less than every ten minutes. MISO shall provide backup capability for all functions critical to reliability.

2. **Visualization Tools.** MISO shall provide its operating personnel with tools to quickly visualize system status and failures of key lines, generators, or equipment. The visualization shall include a high-level voltage profile of the systems at least within the MISO footprint.

3. **Training.** Prior to June 30, 2004, MISO shall meet the operator training criteria stated in NERC Recommendation 6.

4. **Communications.** MISO shall reevaluate and improve its communications protocols and procedures with operational support personnel within MISO, its operating members, and its neighboring control areas and reliability coordinators.

5. **Operating Agreements.** MISO shall reevaluate its operating agreements with member entities to verify its authority to address operating issues, including voltage and reactive management, voltage scheduling, the deployment and redispatch of real and reactive reserves for emergency response, and the authority to direct actions during system emergencies, including shedding load.

6. Corrective Actions to be Completed by PJM

PJM shall complete the following corrective actions no later than June 30, 2004.

Communications. PJM shall reevaluate and improve its communications protocols and procedures between PJM and its neighboring reliability coordinators and control areas.