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KEEPING THE LIGHTS ON: THE FEDERAL ROLE IN MANAGING THE NATION'S ELECTRICITY

HEARING

BEFORE THE

OVERSIGHT OF GOVERNMENT MANAGEMENT, THE FEDERAL WORKFORCE AND THE DISTRICT OF COLUMBIA SUBCOMMITTEE

OF THE

COMMITTEE ON GOVERNMENTAL AFFAIRS UNITED STATES SENATE

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KEEPING THE LIGHTS ON: THE FEDERAL ROLE IN MANAGING THE NATION'S ELECTRICITY

WEDNESDAY, SEPTEMBER 10, 2003

U.S. SENATE,
OVERSIGHT OF GOVERNMENT MANAGEMENT, THE FEDERAL WORKFORCE, AND THE DISTRICT OF COLUMBIA SUBCOMMITTEE,
OF THE COMMITTEE ON GOVERNMENTAL AFFAIRS,
Washington, DC.

The Subcommittee met, pursuant to notice, at 9:02 a.m., in room SD–342, Dirksen Senate Office Building, Hon. George V. Voinovich, Chairman of the Subcommittee, presiding.

Present: Senators Voinovich, Levin, and Lautenberg.

OPENING STATEMENT OF SENATOR VOINOVICH

Senator VOINOVICH. The Subcommittee will please come to order. Because we have a very busy schedule and many witnesses, I want to begin this hearing on time. I am sure that my colleagues will be coming, as I expect several of them to be here today. They indicated that they will be here.

Again, thank you for coming. We are here today to discuss the Federal role in ensuring the reliability of our electricity supply. In order to ensure that we have reliability, we need to have highly dependent systems to operate continuously and for them to generate and transmit electricity. It is axiomatic that adequate generation is meaningless without the transmission capacity to deliver electricity, and equally so to have an adequate or even robust transmission system without adequate generation to meet customer demand.

There is no question that this Nation is currently served by a strained electricity system. Generation has failed to meet growing demand and facing ever-tightening restrictions that limit our ability to expand generation capacity, transmission capacity, and transmission capacity increases have lagged even behind generation increases, let alone demand increases. So, in effect, what we have had is a lot more generation, but we haven't had the transmission capacity to keep up with that generation capacity.

Fortunately, the Senate, along with the House and President Bush, is moving forward in developing an energy policy to help alleviate these constraints. The energy bill will encourage increased production and supplies of natural gas and expansion of hydro-based nuclear and clean coal-fired generation.

Further, I have introduced President Bush's Clear Skies Act, which will provide much needed relief to natural gas markets by protecting the long-term viability of coal-based generation and provide regulatory certainty for utilities, which is something that we need desperately in this country. There is so much uncertainty today out there among generators that it has never been like this in the country's history.

The issue of electric reliability was brought front and center on August 14, when more than 50 million Americans and Canadians lost power in parts of the Northeast, the Midwest, and Ontario. In my home State of Ohio, at least two million—two million people were affected, including yours truly. It was very nice that day when the lights came on about 12 hours exactly from the time that they went out. I landed at Hopkins Airport when the lights went out and it took us about 2 hours to go through the whole procedure. I give the bag handlers a lot of credit for doing everything by hand.

First, I would like to commend the administration for its leadership. President Bush moved quickly to create the U.S.-Canada Joint Task Force on the power outage. By initiating a thorough examination of the blackout and getting the Canadians involved quickly, the administration has put us on a path to discover what happened.

The purpose of today's hearing is not to focus on who was responsible for the blackout. I want to emphasize that. I am confident that all of those questions will be answered by the investigation being conducted by the task force, and in the future, we will be holding hearings on these findings. Rather, today's purpose is to focus on how we prevent something similar from happening again.

Many of us have known for several years that power transmission has not kept up with power generation, particularly in the era of deregulation, where the power grid takes on much greater priority. The point is, even if the power hadn't gone out, we would still be facing potential problems with our outdated and inadequate transmission system.

What action must be taken by the Federal Government to ensure that our grid doesn't collapse again in the future? The August blackout was only the most recent example of why our country's electricity transmission system needs to be modernized. Like all of my colleagues on this Subcommittee and in this Senate, I am truly concerned about our Nation's energy situation.

It may surprise many people in this room that Ohio is the third largest energy-consuming State in the United States of America, behind California and New York. Ohio, as well as other States, needs affordable, reliable energy to ensure a robust economy and future growth. Unfortunately, this blackout has had a costly effect on many of our business interests and sectors. The Ohio Manufacturers' Association estimates that the August blackout directly cost Ohio manufacturers over $1 billion—$1 billion in an economy that is sputtering.

For example, Republic Engineered Products, based in Ohio, experienced a fire and an explosion as a result of the blackout which seriously damaged one of their blast furnaces in Lorraine, Ohio. After this furnace went offline, the most effective solution for the company was to start a back-up furnace, which cost a significant amount of money. Additionally, there was molten steel in their process machinery which cooled when power was lost, causing additional damage to their equipment. The final price tag this company is facing because of the blackouts will be in the millions of dollars. I have heard similar stories from companies in other States affected by power outage, including New York, Pennsylvania, and Michigan.

Over the last 40 years, our national electricity system has become congested and strained because growth in electricity demand has not been matched by corresponding investment in new generation and transmission. Further, our existing transmission infrastructure, which was created in a world where utilities operated as virtual monopolies within their geographic regions, was not designed to meet the demands of our modern electricity markets.

The result is that generation shortages and transmission constraints have led to major blackouts in California—we have forgotten that so quickly, but it happened—the Midwest, and the Northeast, and the risks of further blackouts are growing daily. Many of us were concerned last summer that New York would experience blackouts because of the lack of transmission capacity in that great city.

This is not acceptable. When my constituents flip on the lights, they expect that the lights come on.

I am pleased that modernization of our transmission systems is finally a national priority and is being debated in the energy bill Conference Committee. The need for reliable transmission is universally recognized. However, things break down when policy makers argue about who pays for it. We went through that last year when we were trying to put the electricity title together for the energy bill. Who pays for it? Is it the utilities? Is it the customers? There is an argument. Somehow, that has got to be worked out so that it is a fair way of paying for that transmission capacity.

The fact is that investing in power generation is a better investment than investing in transmission, and somehow, we have to recognize that. It is understandable that companies are hesitant to invest in transmission because they are facing obstacles, such as NIMBY, "not in my backyard," and frankly, I have heard, and I am sure Senator Levin has heard from constituents that don't want transmission lines through their farm and through wherever they live.

To make matters worse, it seems there is a new movement afoot. It is called the BANANA movement, "build absolutely nothing anywhere near anything." Further, even companies that are willing to invest in transmission are reluctant because of burdensome and onerous environmental requirements.

We have to harmonize our environmental and energy policies to keep this Nation competitive. For too long, our environmental concerns, our needs, and our energy concerns have been going in different directions. They haven't been speaking to each other. For the betterment of this country, we need to harmonize those environmental and energy needs or we are in deep, deep trouble.

In an effort to increase transmission capacity, I sponsored legislation in the last Congress to amend the National Environmental Policy Act and streamline the siting process for transmission corridors. Further, I have recently sent a letter to the energy bill conferees encouraging them to include provisions to strengthen the reliability of our Nation's electricity supply in that energy bill.[1]

What I would like to hear from each witness today is your thoughts on the best way to move forward to modernize the grid and what is the appropriate Federal role in managing and regulating the grid.

I now would like to call on Senator Levin. Senator Levin, I am very happy that you are here today, and if you have an opening statement, we would like to hear it.

OPENING STATEMENT OF SENATOR LEVIN

Senator LEVIN. Thank you, and I will ask that my entire statement be made part of the record. I will try to be brief because I know that we have a number of votes coming up, I believe a little later on this morning.

I commend you, Mr. Chairman, for not only calling this hearing, for your initiative and for your leadership in this area, but also for trying to hold a hearing when we have a series of stacked votes going on later on this morning. It is going to be quite a challenge to do that and I thank you for that effort.

Over the past few years, our country and our economy have been rocked by two major energy crises. The first, triggered by Enron's collapse, disclosed rampant energy price manipulation and fraud and billions of dollars in electricity overcharges in a number of States. The second, on August 14, was a sudden and massive power outage that disrupted broad sections of the Midwest, New York, and Canada.

In my home State of Michigan alone, over six million residents lost power. Numerous Michigan businesses and schools closed, including over 70 manufacturing companies. The City of Detroit and much of Southeast Michigan lost the ability to operate water and sewer systems. Michigan State and local governments spent more than $20 million on emergency assistance. And ongoing assessments of losses associated with the power failure in Michigan are expected to reach $1 billion.

The massive power failure of August 2003 on top of the massive price manipulation perpetrated by Enron and others provide additional proof, if more were needed, that the deregulated energy markets in this country are not functioning well. These energy markets are not self-policing. There is no invisible hand guaranteeing efficient power flows and fair prices. Instead, a philosophy that U.S. energy markets can function free of meaningful oversight has thrown our energy markets into turmoil and opened the door to power failures and price manipulation, punishing U.S. ratepayers and taxpayers with economic disruption and high energy costs.

The result is not only unreliable power that threatens our economy and our security, but also a loss of investor confidence in U.S. energy markets, a dearth of new investment, and the bankruptcy of some energy companies once at the heart of our U.S. energy industry.

[1] The letter to Senator Domenici and Representative Tauzin, dated September 3, 2003, appears in the Appendix on page 484.

Despite the growing complexity and difficulties associated with power transmission, it is also clear that currently no single agency or company can be held accountable for ensuring the reliability of the Nation's electric grid. Control of transmission lines varies across the Nation and includes a hodgepodge of Federal, regional, State, local, and private agencies and entities.

One key player testifying today, the Midwest Independent System Operator, MISO, schedules wholesale use of lines to transmit electricity but claims to lack the authority to interrupt power transmissions traveling from energy generators to consumers. Instead, when lines go down, as they did on August 14, the MISO can issue instructions to utilities using the power lines, but must rely on voluntary compliance by the utilities to resolve fast-moving grid problems.

The North American Electric Reliability Council, an industry group that designs and issues standards to ensure grid reliability, is dependent on voluntary compliance and cannot require transmission line users to meet its standards or penalize non-compliance.

The Federal Energy Regulatory Commission (FERC) also says it lacks clear authority to ensure grid reliability, although in 1999 it issued rules which, in part, required regional transmission organizations to ensure reliability.

The August power failure and the Enron price manipulation scandal provide clear mandates for Congressional action. Congress needs to pass legislation this year to increase grid reliability and to stop energy price manipulation.

With respect to reliability, Congress needs to replace voluntary reliability standards with mandatory and enforceable reliability rules applicable to all users, owners, and operators of the transmission network. While industry-developed standards provide a starting point, the responsibility for writing the final rules to ensure grid reliability needs to be vested in FERC, a Federal agency that can be held accountable for problems.

Now, while some in Congress want to include a reliability provision in the larger energy bill now in conference, using the urgency of that issue to propel enactment of the whole energy bill, this issue is too important to hold the reliability provision hostage to resolution of a myriad of other problems in the energy bill. We ought to act on the consensus that now exists to resolve the reliability problem. If we fail to act now, we are risking more blackouts.

And just one word on this other legislation to eliminate the so-called Enron exemption, Mr. Chairman. I will not go into that in detail except to say that Senators Feinstein, Lugar, myself, and a number of other Senators have been working on anti-fraud and anti-manipulation laws. We have been guaranteed and assured that we will have an up-down vote on an amendment to the agriculture appropriations bill to address that issue. We will be releasing a copy of the amendment in the near future and I, again, would appreciate the entire statement on that subject and other parts be made part of the record.

Senator VOINOVICH. Thank you, Senator Levin.

Senator LEVIN. Thank you very much, Mr. Chairman.

[The prepared opening statement of Senator Levin follows:]

PREPARED OPENING STATEMENT BY SENATOR LEVIN

Over the past few years, our country and our economy have been rocked by two major energy crises. The first, triggered by Enron's collapse, disclosed rampant energy price manipulation and fraud and billions of dollars in electricity overcharges in a number of states. The second, on August 14, was a sudden and massive power outage that disrupted broad sections of the Midwest, New York and Canada. In my home state, alone, over 6 million Michigan residents lost power. Numerous Michigan businesses and schools closed, including over 70 manufacturing companies. The City of Detroit and much of southeast Michigan lost the ability to operate water and sewer systems. Michigan state and local governments spent more than $20 million on emergency assistance, and ongoing assessments of losses associated with the power failure in Michigan are expected to reach $1 billion.

The massive power failure of August 2003, on top of the massive price manipulation perpetrated by Enron and others, provide additional proof, if more were needed, that the United States' deregulated energy markets are not functioning well. These energy markets are not self-policing—there is no invisible hand guaranteeing efficient power flows and fair prices. Instead, an ill-advised philosophy that U.S. energy markets can function free of meaningful standards and oversight has opened the door to power failures and price manipulation, punishing U.S. ratepayers and taxpayers with economic disruption and high energy costs.

The result is not only unreliable power that threatens our economy and security, but also a loss of investor confidence in U.S. energy markets, a dearth of new investment, and the bankruptcy of some energy companies once at the heart of the U.S. energy industry.

Reforms can and must tackle these issues. While the precise causes of the August power failure have yet to be determined, and investigations by the Michigan Public Service Commission, U.S. Department of Energy in conjunction with Canada, and others are ongoing, some facts have already become clear. We know, for example that, during the 1990's, utilities in the Northeast and Midwest underwent extensive deregulation that separated electricity power generation from power transmission over the grid. Since this deregulation, according to a recent report by the North American Electric Reliability Council, the Midwest has become one of the great crossroads in the transmission of power across the nation. Power produced as far away as Denver flows through the Midwestern grid on its way to users in New York and elsewhere.

At the same time, the complexities and difficulties involved in coordinating power flowing through Midwestern transmission lines have increased. A patchwork of companies and utilities generating power use these lines. These transmission line users apparently have no legal obligation to alert the transmission line operators to upcoming voltage fluctuations or the cause of these fluctuations, even though power surges can overwhelm transmission lines with little notice and devastating impact. Utilities have no legal obligation to warn neighboring utilities of transmission problems, even though warnings can play a crucial role in activating safeguards to minimize grid problems. Detroit Edison reported, for example, that on August 14, it had no idea there were problems on the grid until 2 minutes before the Michigan power loss, when power flowing from Michigan to Ohio jumped by 2,000 megawatts in 10 second sand, 90 seconds later, power flowing from Ontario to Michigan jumped by 2,600 megawatts. Thirty-seconds after that, Detroit Edison's portion of the grid was dead.

Despite the growing complexity and difficulties associated with power transmission, it is also clear that, currently, no single agency or company can be held accountable for ensuring the reliability of the nation's electrical grid. Control of transmission lines varies across the nation and includes a hodge-podge of federal, regional, state, local and private agencies and entities. One key player testifying today, the Midwest Independent System Operator (MISO), schedules wholesale use of liens to transmit electricity, but claims to lack the authority to interrupt power transmissions traveling from generators to consumers. Instead, when lines go down as they did on August 14, the MISO says that it can issue instructions to utilities using the power lines, but must rely on voluntary compliance by the utilities to resolve fast-moving grid problems. The North American Electric Reliability Council, an industry group that designs and issues standards to ensure grid reliability, is dependent on voluntary compliance and cannot require transmission line users to meet its standards or penalize noncompliance. The Federal Energy Regulatory Commission also says it lacks clear authority to ensure grid reliability although, in 1999, it issued rules which, in part, require Regional Transmission Organizations to maintain short-term reliability in their grid operations.

The August power failure and the Enron price manipulation scandal provide clear mandates for Congressional action. Congress needs to pass legislation this year to increase grid reliability and stop energy price manipulation. With respect to reliability, Congress needs to replace voluntary reliability standards with mandatory and enforceable reliability rules applicable to all users, owners, and operators of the transmission network. While industry-developed standards provide a starting point, the responsibility for writing the final rules to ensure grid reliability needs to be vested in FERC, a federal agency that can be held accountable for problems. While some in Congress want to include reliability requirements in the larger energy bill now in conference, using the urgency of this issue to propel enactment of the whole bill, this issue is too important to hold resolving the reliability problem hostage to the resolution of a myriad of other problems in the energy bill. We ought to act now on the consensus that has apparently arisen on the need to strengthen grid reliability. If we fail to act now, we are risking more blackouts.

Congress also needs to enact legislation to eliminate the so-called Enron exemption that, in 2000, exempted certain energy transactions from federal oversight and federal anti-fraud and anti-manipulation laws. Senators Feinstein, Lugar, and I, as well as a number of other Senators, have been working on this legislation. When the Senate simply adopted last year's energy bill without addressing this issue, the Senate Majority Leader promised us an up-or-down vote on an amendment to the Agriculture appropriations bill this fall, and we plan to circulate a bipartisan amendment addressing this issue in the near future. It is incomprehensible to me that some people are lobbying to maintain the Enron exemption and to stop efforts to strengthen federal anti-fraud and anti-manipulation laws. It is long past time for Congress to make it clear that fraud and price manipulation are unacceptable in any sector of the U.S. energy markets.

I commend the Chairman for holding this hearing and look forward to the testimony.

Senator VOINOVICH. Senator Lautenberg.

OPENING STATEMENT OF SENATOR LAUTENBERG

Senator LAUTENBERG. Thanks, Mr. Chairman. I am appreciative that you are calling today's hearing on the blackout. It is so fresh in our memory and so dark a spot on the horizon.

The loss of power on August 14 brought a large swathe of the country to a standstill and reportedly cost New York City alone $1 billion. Now, in my opinion, this event dramatically demonstrates where we are headed if we fail to modernize the Nation's electrical transmission system, but other factors may also have been involved and we will need answers about exactly what happened and why it happened. If we fail to correct the flaws in these systems and soon, many believe more regions will be brought to their knees.

Shutdowns come with a high price tag: Massive public inconvenience; increased dangers for Americans, especially for Americans like those who are in the air depending on air traffic controllers with their electric systems to safely land them.

But reliable electricity is not a new issue. Since 1978, the country has been inching toward deregulation and some regions have made great progress while others locked in outmoded systems dating back to the beginning of electricity regulation in this country. I understand that some of my colleagues have concerns about electric industry deregulation. But in my State of New Jersey, we are part of the PJM interconnection. It is the country's first fully operating regional transmission organization, the world's largest competitive wholesale electricity market.

The ratepayers in New Jersey have reaped enormous benefits from belonging to this RTO, including stable rates that have not risen in 11 years. Just as important, and more to the point of this hearing, during the blackout, only 7 percent of PJM's 25 million customers lost their power. Now, 7 percent is not insignificant, but compared to 98 or 100 percent, it is pretty darn good.

So I would like to hear from today's witnesses about their views on additional RTOs that centrally dispatch information, like PJM. Had more of these been operating on August 14, the question is, could the blackout have been better contained?

The *Wall Street Journal* noted in an August 18 editorial that adequately addressing the issue of electricity reliability will take political will and regulatory common sense, and it is my hope that my fellow Senators and I will rise above the entrenched political positions that are not serving the public's needs for a modern, reliable electricity grid. Today, I am looking forward to hearing some regulatory common sense from these witnesses.

I thank you, Mr. Chairman. I hope we will arrive at some direction to take to cure this problem.

Senator VOINOVICH. Thank you, Senator.

We have an impressive lineup of witnesses this morning and I look forward to an informative discussion. As Senator Levin said, we have stacked votes, so this is going to be interesting to see how this all works out.

Our first witness today is Deputy Secretary of Energy Kyle McSlarrow. He is joined by Patrick Wood, the Chairman of the Federal Energy Regulatory Commission. I thank you both for testifying today. I would also like to note that Jimmy Glotfelty, the Director of the Office of Transmission and Distribution, is also attending this hearing.

As is the custom here, I would like you to please rise and be sworn in.

Do you swear the testimony that you are about to give before the Subcommittee is the truth, the whole truth, and nothing but the truth, so help you, God?

Mr. MCSLARROW. I do.

Mr. WOOD. I do.

Senator VOINOVICH. The record will reflect that they answered in the affirmative.

Mr. McSlarrow, we will start with you.

TESTIMONY OF KYLE E. McSLARROW,[1] DEPUTY SECRETARY OF ENERGY, DEPARTMENT OF ENERGY

Mr. MCSLARROW. Mr. Chairman, thank you. Let me first say that we appreciate your leadership on such important issues as transmission reliability and a robust, competitive wholesale market that benefits consumers. I would like to note that you and Senator Levin were among the first to contact our Department to ensure that we were fully engaged when the blackout occurred on August 14. Since then, as you mentioned, we have made good progress in our effort to determine the causes.

As you know, within a few hours of last month's blackout, President Bush and Prime Minister Chretien ordered a cooperative, binational investigation into that incident. Top government officials from both countries and scores of technical and engineering experts

[1] The prepared statement of Mr. McSlarrow appears in the Appendix on page 61.

have been hard at work ever since to determine exactly what caused this outage, how it was allowed to spread, and what can be done to reduce the chances of such an incident in the future.

While Secretary Abraham has the lead on this task force, I do want to recognize the personal leadership exhibited by Chairman Wood and all of FERC staff, who put in long hours to ensure that we get the right answers as quickly as possible.

Once we have determined the causes of the blackout, we will enter Phase II of the task force's two-part assignment, which is formulating recommendations to address the specific problems we uncover. Any recommendations the joint U.S.-Canada task force makes will likely focus on technical standards for operation and maintenance of the grid and on the management of performance of the grid in order to more quickly correct the problems we identify. We are determined to complete this inquiry in a timely manner. We hope to have conclusions and recommendations in a matter of weeks, not months. As Secretary Abraham has said, we will not compromise quality for speed.

Beyond the investigation, there is also the broader focus on the Federal role in electricity reliability. The President's National Energy Policy noted that one of the greatest energy challenges was to improve our Nation's aging energy infrastructure and particularly the transmission infrastructure. The National Energy Policy also called for a transmission grid study, which our Department conducted and completed in May 2002. That study outlined the current condition of our grid and recommended ways to promote the expansion of overall transmission capacity, elimination of the bottlenecks on the grid, and enhancement of the grid's technical efficiency and improvement of the system's reliability.

There are several measures before the House and Senate Conference on the energy bill right now that would codify some of the recommendations included in the President's National Energy Plan and our Department's grid study. Since the President's first days in office, the administration has strongly supported proposals to establish mandatory and enforceable reliability standards to reduce the risk of power outages. We were pleased that both the House and the Senate included provisions in the energy bill to establish those standards.

We also support proposals that would expand investment in transmission and generation facilities by repealing the Public Utility Holding Company Act, which has limited the resources that can be invested in a transmission system.

We strongly support measures to provide greater regulatory certainty for transmission expansion, including provisions providing for last resort Federal siting authority for high-priority transmission lines and providing for the coordination and streamlining of transmission permitting activities across Federal lands.

We support options that would allow for increased rates of return on new transmission investments, including clarifying FERC's authority to provide incentive-based rates to promote capital investment in new transmission.

We support the goal of regional coordination and planning through the mechanism of voluntary regional transmission organizations that would provide certainty to the marketplace, prevent undue discrimination, and assist in eliminating transmission constraints. And we support changes in Federal tax law to allow the recognition of gain over 8 years for the sale or disposition of transmission assets as part of restructuring and to allow rural cooperatives to provide open access to their transmission systems without losing their tax-exempt status.

Before I close, Mr. Chairman, let me just add that government research and development has an important role to play here, as well. That is why the President's 2004 budget request includes additional funding for high-capacity technologies, such as high temperature superconducting transmission lines and for real-time grid management tools to enhance reliability.

Our electricity system is the backbone of the U.S. economy. We probably don't think about something so obvious until the lights go out, but we cannot afford to let such a vital component of our infrastructure fail and I am confident that Congress will send an energy bill to the President this fall that sets us on a course to successfully address those challenges.

Mr. Chairman, that concludes my testimony.

Senator VOINOVICH. Thank you very much. Chairman Wood.

TESTIMONY OF PAT WOOD, III,[1] CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION

Mr. WOOD. Thank you, Mr. Chairman, Senator Levin, and Senator Lautenberg. As the Deputy Secretary just outlined, the FERC and its staff are participating as members of the joint U.S.-Canada Task Force to look at what actually happened, why it cascaded across such a broad territory. And while the analysis of this voltage collapse is ongoing, I will refrain from, as you indicate, for the purpose of this hearing, we are not going into that anyway, but will refrain from trying to analyze too deeply until we get the facts, because I think the facts should drive us wherever they lead.

The Federal role in electricity grid management is the focus of your hearing today, and from the outset, let me be clear. As I believe Senator Levin just pointed out, our explicit authorities under the Federal Power Act and other statutes in the area of reliability are very limited. However, we do have some insight into regional grid management deriving from our role primarily as the economic regulator of the electricity industry and I think that can provide some insight, as you requested in your letter of invitation, Mr. Chairman.

The blackout illustrates, as have many other events in the past couple of years, that the power grids are regional in nature. After each significant blackout, which were 1996, 1999, 2000, 2001 in California, and this year 2003, the Nation has taken significant steps forward to recognize that we are, in fact, interconnected and regional and to develop new rules and institutions that recognize this fact.

For example, after the 1965 blackout in the Northeast, the NERC was created to create regional and voluntary reliability standards. That is the subject of the legislation in conference today. That would actually make that mandatory.

[1] The prepared statement of Mr. Wood appears in the Appendix on page 71.

After the 1996 blackout across the West, the governors and institutions out there developed a regional transmission plan that led to significant investment in the grid. I do have to add that I think that needs to continue. I believe that this blackout, similarly, will warrant significant action toward better regional grid management, as well.

Prior to my term on the Commission, the bipartisan commission back in the 1990's issued Order 2000, which encouraged, but did not require, the formation of regional transmission organizations, such as PJM that Mr. Lautenberg talked about. The expectation at the time was that these would form across the country by the end of 2001 and that they would be able to assume full control of the regional grids.

The Midwest, however, is a good example of the fits and starts and the difficulties that the voluntary RTO program has had in achieving independent regional control in many areas. In such a voluntary arrangement, key principles like governance, independence, and even reliability are subject to negotiation and compromise.

In Order 2000, the Commission stated that RTOs would have public accountability for reliability. RTOs would improve reliability because they have a broader, more regional perspective than individual local utilities, which number presently 130 independent control areas in the country that are actually the managers of the grid implementing the voluntary NERC standards.

RTOs, as we have seen, have the ability to take action if they have the operational authority to do so. An RTO can end the balkanization within the region of the grid and assign it exclusive authority for short-term reliability. In fact, these characteristics are embedded in Order 2000 and they relate to the appropriate independence of the entity to run the grid, the appropriate scope and regional size of the grid configuration, full operational authority of the grid, and the exclusive authority to oversee short-term reliability, which are the NERC standards.

RTOs also provide long-term transmission infrastructure development, a regional planning process, a regional rate recovery process through tariffs that are administered and are applied on a multi-state basis. These are developed through stakeholder processes and have been very successful in the regions where we have them. I think that regional investments are going to be almost impossible to make if you do not provide investors a very clear path for recovery of those new investments that I think, Mr. Chairman, you have pointed out. As a common sense matter, we know they need to be made, and we have been knowing this for a few years. But the problem is, an investor is not going to sink money if he or she doesn't know how the money is going to get back with a return.

This spring, after a year and a half of hearings and workshops and road trips and written comments, we put out a vision for a wholesale power market platform. It is also known by its earlier name, standard market design. We recognize the regional nature of the power grid and the uncertainty that is created by having balkanized systems across the country. The platform would mandate participation in RTOs and require a transition process.

Many other features are left to regions to design and for State officials to participate in, crafting the details. But as a practical matter, we do need platforms upon which regional grid management can happen so that the benefits that we all know can happen, that we have seen in parts of the country where this planning has gone forth, can move forward. Thank you.

Senator VOINOVICH. Thank you. We will limit our questions to each of the Members of the Subcommittee to 5 minutes and rotate it.

The two of you have had a chance to observe what has happened here in the last several years and most recently on August 14. The real question that I have is, what is the best way of ensuring that it doesn't happen again and that we have the reliability that is out there, and who should be in charge of the whole operation?

In other words, we have had a kind of a mixed system out there. FERC has a role and the independent systems have a role, and you have the regional groups. How do we improve that system so that we don't have what happened on August 14?

Mr. MCSLARROW. Mr. Chairman, I think that there are several different answers, but the most obvious one is to pass the energy bill that includes the provisions that I outlined in my testimony.

Senator VOINOVICH. You believe that the provisions that are in the energy bill now, which is in the Conference Committee, will get the job done?

Mr. MCSLARROW. They will get most of the job done. What I don't know and we won't know until we conclude our task force investigation is whether or not there is something specific to August 14 in addition to the recommendations that I have outlined that are included in the Conference.

But the energy bill in Conference has a robust electricity title. It deals with siting. It deals with incentives for transmission. It deals for encouraging the development of regional transmission organizations. It deals with FERC's ability to clarify those roles and provide incentives. It does a lot, and most importantly, it includes mandatory enforceable standards that are implemented by the National Electric Reliability Council and enforced by FERC. So I can't say right now it will do 100 percent, but it will do——

Senator VOINOVICH. Implemented by the Reliability Council, but they are enforced—FERC's role will be to enforce and make sure that they are carried out?

Mr. MCSLARROW. Yes, sir.

Senator VOINOVICH. Which is not the case today?

Mr. MCSLARROW. Yes, sir, that is right. Today, it is a voluntary reliability regime and FERC has no authority to enforce that, nor does NERC, for that matter, and there is certainly no penalty for not playing by the rules.

Senator VOINOVICH. Well, we are hoping you get an energy bill out before the end of the year. The joint U.S.-Canadian study, you said it is not going to be months, it is going to be weeks. How long do you think that it will take before we wrap that up to determine whether or not they come up with something that ought to be added to the provisions of the energy bill?

Mr. MCSLARROW. I would say we should do the energy bill as quickly as we can. We will get our task force completed as quickly as we can. If there are recommendations and it is still timely to add to the energy bill, we will, but the administration would urge that we not slow down the energy bill. It is important to get it done. If there are additional recommendations, we will come and make those to Congress. There are plenty of vehicles that we can add that I am sure will have widespread bipartisan support to ensure that the outage of August 14 doesn't occur again. But we would urge to move forward as quickly as possible on the energy bill.

Senator VOINOVICH. Mr. Wood.

Mr. WOOD. On the more granular level, that being the legal framework that would be clarified——

Senator VOINOVICH. Mr. Wood, I just want to say something. You are the Chairman of the FERC.

Mr. WOOD. Yes, sir.

Senator VOINOVICH. You have, what, three members now?

Mr. WOOD. We are down to three, yes, sir.

Senator VOINOVICH. OK. I understand that you are not even capable of doing things because you need two more members?

Mr. WOOD. Oh, no. We are doing fine.

Senator VOINOVICH. Are you?

Mr. WOOD. We are down two, and——

Senator VOINOVICH. You don't need another two members?

Mr. WOOD. We are look forward to them being here, yes, we do. [Laughter.]

We definitely do.

Senator VOINOVICH. Well, I think that we ought to move as quickly as we can so that you have those two new members.

Mr. WOOD. One of our three, however, his term would be up when Congress adjourns, so at that point, we do have trouble.

Just to follow up on Mr. McSlarrow's comment, getting the legal clarifications of that world out there are certainly helpful. The uncertainty that is created by not knowing what the future looks like makes investment an almost non-event. So I do want to strongly urge from the Commission's perspective, that is kind of down a little bit more in the trench, that we really do need the Congress to say this is what the energy world is going to look like. Putting it off for yet another session just means 2 more years of investor uncertainty, and quite frankly, we have had that for quite a while and we need to move on.

So I do want to recommend, as Mr. McSlarrow did, that we do get the energy legislation out. I think it has got potential to really clarify a lot of issues here. Our job is to take it to the doability point and to take the mandatory reliability rules that NERC and its experts would work up and go through a public vetting process. If, for example, we find that those conflict with some other Power Act obligation, we have an obligation under the proposed bill on both the House and the Senate side to kick it back and say, rethink this because of these issues.

We have to delicately balance this oversight role because it is also going to be overseen by independent Canadian authorities, and so this, as we saw, it is an international power grid. We have to make sure that—and I think the law has been written in a way that is very respectful of that. So those are the kind of delicate things on reliability.

The question is, OK, who is going to actually implement these standards on a day-to-day basis? Are we going to have it be the 130 independent utility control areas, some big, some small, across the country, or are we going to try to look at that on a more regional basis, as we were talking about earlier in our opening statements. I do think that the regional model is clearly the correct way to go and also the common sense way to go.

Senator VOINOVICH. Thank you very much. My time is up. Senator Levin.

Senator LEVIN. Thank you, Mr. Chairman.

I would like to ask about the current authority that FERC has in this area of regulation. FERC indicates it is not a clear authority to assure reliability, but the regulations which have been issued, the orders which have been issued by FERC, suggest otherwise.

In February of 2000, FERC issued the final rule, an order entitled, "Regional Transmission Organizations," the RTO, which "codifies minimum characteristics and functions that a transmission entity must satisfy in order to be considered an RTO." You grant RTO status to regional entities, such as MISO, that operate transmission lines in Michigan and Ohio.

In the order, it says that it establishes required characteristics and functions for these RTOs for the purpose of promoting efficiency and reliability. Then the order goes on to state that an RTO "must ensure the integration of reliability practices within an interconnection and market interface practices among regions." And it goes on to say that the RTO "must have exclusive authority for maintaining the short-term reliability of the grid that it operates." So it sounds like you have authority now and, indeed, will not certify or will not license an RTO unless it does those things.

Mr. WOOD. Correct.

Senator LEVIN. What is lacking?

Mr. WOOD. Well, that whole program has requirements and obligations, but it is not—it is a program that utilities volunteer to be in. So the predicate for all those required characteristics is really set back in that rule, which our proposal of recent months would change and make mandatory for everybody. But that rule in 1999, which was finished up in 2000, is at its heart an encouragement or voluntary. So the legal authority on that was, I don't think, a problem, but it was one that the Commission chose not to exercise at the time.

Senator LEVIN. Can you refuse, then, to certify an RTO?

Mr. WOOD. We could, yes, sir.

Senator LEVIN. And then what would be the penalty? Why would an RTO care if it were not certified? In other words, if you can insist that there be reliability standards that an RTO will adopt——

Mr. WOOD. Under current law——

Senator LEVIN [continuing]. As part of the certification process, why isn't that enough power right now to achieve those reliability standards?

Mr. WOOD. Where you have utilities agreeing to get into an RTO, you are correct. There is no question there. Where you have got some that do and some that don't, or some that will and some that won't, then you do have some concerns, and that is actually one of the issues we have in the Midwest, is you have some utilities that have not joined up with an RTO and there are basically holes in the Swiss cheese.

Senator LEVIN. The standards which are in the House and the Senate bill, I take it, are adequate as far as you are concerned in the energy bill to achieve the authority that you need to make mandatory these standards, reliability standards?

Mr. WOOD. Yes, sir.

Senator LEVIN. OK. You, Mr. McSlarrow, the Energy Department supports those provisions, I understand.

Mr. MCSLARROW. We do, yes, sir.

Senator LEVIN. Now why, if the energy bill—if, and I know it is a big if—it runs contrary to your hopes, perhaps your expectations, but at least your hopes—if the energy bill doesn't look like it is going to pass this year, why is it not essential that we pass these provisions to assure reliability and that there is not a repeat of the blackout? Why do we hold them hostage to the rest of the energy bill, which has all kinds of complicated provisions where people are in dispute over them? We have everything from the Alaska wilderness to things which are almost as complicated as that.

Why should we say that we are not going to do what we need to do to prevent a future blackout and give FERC what it needs in terms of authority until and unless we get all these other energy issues resolved?

Mr. MCSLARROW. I don't think that it is just about NERC's reliability standards.

Senator LEVIN. About——

Mr. MCSLARROW. About these mandatory reliability standards. And quite frankly, I have not met a utility official or an engineer who hasn't treated them as if they were mandatory. So, I mean, making them voluntary to mandatory does, yes, put the stick a lot bigger, because now you can do monetary penalties.

But at its core, there is more in the energy bill than just this and it is that certainty that I was mentioning in my answer to Chairman Voinovich, is that we can make all the reliability standards in the world, but if you don't have anybody that wants to come and invest in upgrading the grid, not just big new power lines. We might need some of those, sure.

But investing the kind of smart technologies that are out there that are dying to be implemented on the grid that utilities have zero incentive to employ right now if they don't understand what the regulatory and investment framework is going to be. And I will say, there are a number of provisions throughout both the House and Senate bills that do provide, I think, good contours for that investment certainty for the next 10 years.

Senator LEVIN. It would be less likely that they will invest?

Mr. MCSLARROW. Yes, sir, if we just have——

Senator LEVIN. That is fine.

Mr. MCSLARROW. If we have no bill or just a stand-alone reliability bill, I think.

Senator LEVIN. I understand there would be less incentives, but you still need these reliability standards. There may or may not be those kind of investments. Those are presumably positive features.

But in the meantime—and you are not guaranteeing that investment with the energy bill, with those other provisions. You are just presumably facilitating.

But on this, we know there is a consensus that we need to give for this power to force these regional entities, these regional councils to take the steps to make these mandatory, and if they don't or if they are not adequate, for FERC to substitute its own standards. So they will do some good by themselves. They will clarify your power by themselves. And so it seems to me that we are risking needlessly, we are risking that additional clout by linking it to all of these other provisions.

I am talking about all the other provisions of the energy bill. I am not talking about the ones that you have just outlined. I am talking about drilling in Alaska and everything else that is in here.

Mr. MCSLARROW. Senator, if we are at the end of session and nothing has happened on the energy bill, I am certainly not prepared to say today that we are going to take off the table any options between the administration and the House and Senate leadership.

I will say this. We have lurched from energy crisis to energy crisis, from California at the beginning of our administration to gasoline prices to oil prices to natural gas shortages, back to electricity, to home heating oil, and every time, there is something in the energy bill that could be taken out and passed right then. And our view is, we need to stop this and pass a comprehensive energy bill. So before we get to that point, I think we should do everything we can to get it done.

Senator LEVIN. And if you get to that point, you are open minded?

Mr. MCSLARROW. I am open minded, yes, sir.

Senator LEVIN. Thank you. My time is up.

Senator VOINOVICH. Senator Lautenberg.

Senator LAUTENBERG. Thank you, Mr. Chairman. I am curious as to whether or not there are mandates or requirements for RTO formulation or any indication of a preference by FERC that suggests that this is a good way to operate. I mean, there was a mention of it in the statement that Mr. Wood made, that PJM functioned very well because we had the capacity to control the switches and the supply, the connections that were necessary to keep our lights on with a relatively minimal effect.

So is there anything in the regulation that says or in the rules that say if there must be an RTO, that there should be an RTO. Is that what you're thinking? Has any direction been given? Are we in our area just lucky that, by chance, we had formed this RTO?

Mr. WOOD. I would think one should never discount luck. I think the ability of the utilities actually started back in the 1920's, Senator Lautenberg, in the Pennsylvania, New Jersey, Maryland, and Delaware areas, including the District. However, yes, in 1999, the question that Senator Levin was asking me about, the Commission that I chair now did put forth a detailed set of standards that should be met on a voluntary basis by the utilities under FERC jurisdiction throughout the country. I think the Commission at the time hoped that that would happen over an 18-month period. It did with a few utilities, but—and particularly throughout the West, with the exception of California, and in some Southeastern States—we have not seen a lot of forward progress on coming together on that.

And then throughout the country, random utilities are not participating, either because they are not FERC jurisdictional or they just choose not to because it is not a requirement. So, actually, we have proposed, and have out there, a rule that would make that mandatory and that is what the subject of some debate is here in the Senate.

Senator LEVIN. Mr. McSlarrow, last week's House hearing on the blackout, Secretary Abraham indicated that the initial investigation findings of the blackout task force will not be open to the public. But DOE has also publicly stated that it wants a transparent process. Now, what is going to happen here? Is it going to be transparent, open to the public, or is it going to be filtered, censored, or husbanded by the administration?

Mr. MCSLARROW. There are two different things going on. The first is the investigation. This is not like we are having a series of public policy meetings. These are actual investigators looking at data on computers and interviewing operators of the grid, operators of the ISOs. This is the same thing that was taking place all over America with any law enforcement agency. Normally, you don't have the public traipse along with you doing that.

Once they get the findings, then we actually move to a policy phase where we are thinking about recommendations. Secretary Abraham did testify, and I know it is his intention, that we will have as open and transparent a process as possible.

Senator LAUTENBERG. I hope so, because the public is a partner here. We hear grumblings. People say, well, it is going to cost more for the users, for the ratepayers to get this thing into shape. But then, in my view, we have to take a look back, see what the operating results were of these companies, what did they do with their reserves, did they build any reserves, and why didn't they move ahead on some of these things.

Mr. Wood, you talk about state-of-the-art digital switchings, things that I think are dying to be used in the current system. Well, if that is the case and we have technology, we understand what it is that would keep things going, then why haven't we moved? Was there such an overwhelming profit motive for this commodity material that they just said, well, the heck with that. We are not going to do it until we are forced to do it. Where would the automobile business be if they didn't improve the design on a constant basis? Where would other industries be?

So what happened here? Why weren't these investments made, do you think?

Mr. WOOD. From the FERC side, we do get all the financial data and we are looking from really tracking all the utilities involved in this blackout from 1990 forward to get an idea of what kind of investments were made. I don't have any data at this time to share, but we will be including that with the broader study going on here to just understand what sort of investment has been made in the transmission grid by the current people doing that and get a better understanding why that went up or down. But I don't have a specific answer to your question today.

Senator LAUTENBERG. I can tell you that the ratepayers will not joyfully write checks and say, OK, well, we have to fix the systems. You said something. Investors want to know what is going to happen if they put money in there and they have a right to know that. There are opportunities for financing, especially in periods like this when the cost for money is relatively low, and I would hope that the target isn't the ratepayer who is going to be asked to pick up the load because the system was faulty.

Do either of you think that if we had RTOs in place, more RTOs in place, that wouldn't it have been possible to prevent the blackout from occurring?

Mr. MCSLARROW. Go ahead.

Mr. WOOD. I want to resist the urge to just say yes and be quiet there, but——

Senator LAUTENBERG. No, don't.

Mr. WOOD [continuing]. I do think some aspects of RTOs were very helpful. I mean, there is an understandable debate about what energy markets should do and what they should look like. Should they be like PJM or should they be something less than that? And that is a fair debate to have. We have it a lot.

But at the core, the RTO is a transmission operator of a regional grid that recognizes what the laws of physics have told us long ago, that this product is going to flow where the path of least resistance lies, not where State boundaries or utility boundaries lie. So at its core, you have got that business plan going on there.

And so to the extent an RTO does bring together and get investment and get the kind of real-time control systems where you can see, in fact, that that line is out, that line is on, this one is sagging, to have that information come in at one time over a broad area, not just for one small utility but for the entire area, yes, I think had we had some of the utilities in the Northern part of Ohio all part of the same interconnected and real-time communicated grid, that might have been a different outcome, sure.

Senator LAUTENBERG. Yesterday, I was visited by several employees of First Energy and they reported to me that the company is using power transmission lines at well over capacity and has failed to replace sections of an old unreliable infrastructure. Can FERC play a role to address this kind of irresponsible part of behavior on the part of a utility?

Mr. WOOD. I think we can. As I mentioned, we are talking to folks of that nature. I am not sure if it is the same ones as part of the broad investigation with the task force. And if there are specific issues that relate to FERC's mandate as opposed to that of the Canadians or the other American agencies, we will pursue those independently.

I do think this is probably an area where mandatory reliability standards as opposed to the voluntary ones makes a difference—and the main difference there is you can put a price tag on violating a mandatory standard. If a mandatory standard is, you can't exceed 105 percent of the capacity more than ten minutes out of a day, or whatever the standard would be, then that has a financial consequence attached to that.

We do not have that today. Now, a State may have that authority. Some States do and some don't. But we clearly do not. That would change with the reliability legislation in both chambers.

Senator LAUTENBERG. Mr. Chairman, I will conclude with that, but I would hope that we go further in developing information because it is very hard in this kind of a fairly short burst to get the data that are needed. I think that there is an opportunity—should be an opportunity for us to thoroughly review the past performance of these firms, to have it done and presented to us or to the Congress generally, about what took place when things were better and whether there was any preparation at all for the expansion that was inevitable as our population grew and demands were increasing.

So I commend you for doing this, but I think that there is a lot more that we have to learn before we are satisfied that it is not going to be the ratepayers doing this.

Senator VOINOVICH. One of the things that I have mentioned is that it is my intention that once the report is finished, to have hearings on that report. It is going to be public. We are going to have people in here and we are going to go over the report. I would rather wait until everybody has got all the information to do it rather than do it prematurely, as is so often the case around here. Sometimes, we never do get to the real cause of something because you have tackled it before people have had the facts before them.

I would like to thank the panel very much for being here today. I just want to make one thing clear again. Both of you feel that to remedy some of the things that we have talked about here, particularly Senator Lautenberg about what people should do and shouldn't be doing. You believe that the language in the energy bill electricity title gets the job done.

Mr. MCSLARROW. We do.

Senator VOINOVICH. That is what I am worried about. I want to make sure that since this new incident on August 14—that there isn't anything new that has come to the surface that ought to be reflected in that language so it is as comprehensive as possible.

I would also like to mention that I happen to believe that this should stay in the energy bill. It is long overdue that this country have an energy policy. There is so much uncertainty out there, not only in this area, but also what utilities can do to reduce their NO_x, SO_x, and mercury emissions, and it is a chaotic situation of lawsuits. It is a maze, as a matter of fact. We need to clear that out and let everybody know where they stand, and if they get out of line, that they are going to pay a steep penalty for getting out of line.

I hope that you keep staying with this and keep the administration on it, that we have to get an energy bill out and we have to get it out as soon as possible. Thank you very much for being here today.

Mr. WOOD. Thank you.

Mr. MCSLARROW. Thank you, Mr. Chairman.

Senator VOINOVICH. We are going to recess for a few minutes. There is 4 minutes left in the vote. So we are going to go over and vote and then we will stick around for the vote on the next bill and then come back and we should have about 35 or 40 minutes so that maybe we can get the testimony from our witnesses that are here today. Thank you.

[Recess.]

Senator VOINOVICH. The Subcommittee will come back into order. I want to apologize to the witnesses. We never know in the Senate what is going to happen and we had some stacked votes then. We are going to try and get as many of you in as we possibly can. I have to go back. I have about 20 minutes between now and then and I will try to have the next vote, which is very important because it is an amendment that I am cosponsoring, and then we will see how it works out.

You all know who you are and I am glad that you are here. For the record, on our second panel we have Dr. Alan Schriber, who is Chairman of the Public Utility Commission of Ohio. Thank you for being here, Dr. Schriber.

Next to Dr. Schriber, he has his predecessor, Craig Glazer, who was former Chairman of the PUCO of Ohio, and now is Vice President of PJM, and someone that has worked with me on energy issues since he was in the Water Department of the City of Cleveland and we rewrote the public utilities law of Ohio. And then when I became governor, I made him Chairman of the Public Utilities Commission, and Craig, I am glad that you are here.

James Torgerson is the President and CEO of the Midwest Independent System Operator. William Museler is the President and CEO of the New York Independent System Operator.

And rounding out the panel, James Kerr, a Commissioner of the North Carolina Utilities Commission, and Dr. Mark Cooper, the Director of Research at the Consumer Federation of America.

I wish the witnesses would stand up and I would swear you in, as is the custom.

Do you swear your testimony is the whole truth and nothing but the truth, so help you, God?

Mr. SCHRIBER. I do.

Mr. GLAZER. I do.

Mr. TORGERSON. I do.

Mr. MUSELER. I do.

Mr. KERR. I do.

Mr. COOPER. I do.

Senator VOINOVICH. The record will show that they all answered in the affirmative. We will start out with Mr. Schriber.

TESTIMONY OF ALAN R. SCHRIBER,[1] CHAIRMAN, PUBLIC UTILITY COMMISSION OF OHIO

Mr. SCHRIBER. Thank you, Mr. Chairman, and thank you for the opportunity to be here. My testimony, I won't read. If it is submitted for the record, that would be great.

Senator VOINOVICH. May I say something? You all heard the testimony before from the other two witnesses, I think, didn't you?

Mr. SCHRIBER. Yes.

Senator VOINOVICH. And you also heard the questions from Senator Levin and you also heard the questions from Senator Lautenberg——

[1] The prepared statement of Mr. Schriber appears in the Appendix on page 88.

Mr. SCHRIBER. Yes, sir.

Senator VOINOVICH [continuing]. And you heard some of my questions. If you want to sprinkle in some of your reactions to that, I would be very grateful.

Mr. SCHRIBER. OK, sir.

Senator VOINOVICH. I am particularly interested in whether or not the language in the energy bill, which I am sure most of you are familiar with, is adequate to get the job done or if you have some problems with that language. I am going to be very much involved, and have been, with that bill, and I would sure like to hear from any of you if you think they have left out—there is a big hole, or there is something in it that we feel goes too far or whatever your opinion is.

I want to fix the problem, and we will talk about this investigation after they get the job done. But we have this wonderful opportunity to make a difference and I want to make sure that we don't miss this opportunity.

Mr. Schriber.

Mr. SCHRIBER. Thank you very much, and I will note that I am a member of that binational task force and I would look forward to delving into that and hopefully someday reporting back to you.

Just to get to the point, which I know you want to do, we want to talk about reliability for a moment because I think everybody agrees that reliability is a critical issue. I think for clarity, we need to understand that reliability can take on different meanings. In the arcane world of electricity that we deal with, we talk about reliability in terms of security and resource adequacy. I think what we are talking about now, in light of the blackout of August 14, is the physical properties of the network, of the system, of the grid. How secure is it? Is it reliable? Is it going to break? I think that is really important.

I don't think we have a third world system. I think what we do need is rules and we need standards. We need NERC and FERC to have the authority to promulgate and enforce those rules, and I think the States can play a very prominent role in enforcement.

As you know, having been governor, Mr. Chairman, in Ohio, as in other States, we enforce—the State enforces rules that are promulgated by other Federal agencies, highway rules, rail rules, and so forth, and there is a good argument that can be made for having the ability to enforce rules that are for FERC, if you will. But I think, again, we all agree that is very necessary and I would say that the reliability provisions of that electricity title are absolutely essential.

I also agree with Chairman Wood that optimum allocation of resources, of dollars toward the system, to the extent that it needs to be fixed, and again, I don't think it is a third world system. I think it is like a highway system. It is broken down in some places. It needs to be fixed in others, and in some cases, congestion needs to be taken care of. I think dollars need to flow where they need best be invested and I think this is done only if you have a control which takes place over a larger area than among 12 fragmented transmission systems, as we have in the Eastern Interconnect.

So, therefore, I would urge you and your colleagues to give FERC the authority they need to move forward in establishing these large, centralized transmission systems that embrace not just one or two, but a very large section of the Eastern Interconnect. I think that gives FERC the ability to put these organizations in place, and within those organizations, I believe decisions can be better forthcoming.

Senator VOINOVICH. Can FERC right now order a utility into an RTO?

Mr. SCHRIBER. No, but the States in some cases have, where mergers have taken place. As merger agreements or as provisions, like in Ohio's law, States—rather, utilities were ordered to join RTOs.

Senator VOINOVICH. So that right now, the power is in the States to get utilities to join RTOs, and this legislation would give FERC the power to order them in?

Mr. SCHRIBER. That is correct.

Senator VOINOVICH. OK.

Mr. SCHRIBER. We would hope. The States said, at least our State has ordered that, and it has been a provision some mergers. At any rate, I think FERC should be supported in their endeavors.

And, I think those are the two main provisions. We could talk about the Public Utilities Holding Company Act. I would have no problems with that being suspended or rescinded. I think that we are likely to hear some arguments in opposition. They have to do with deregulation as being a problem. And I am prepared, although I won't go into it now, but upon questioning, I would be prepared to take issue with that. I don't think deregulation has much, if anything, to do with what is going on.

I think with that, I know you want to move on and I know you want to hear what others have to say with respect to the questions that were raised here, so I will conclude with that.

Senator VOINOVICH. Thank you. Those comments were wonderful.

Mr. SCHRIBER. Thank you.

Senator VOINOVICH. Mr. Glazer.

TESTIMONY OF CRAIG A. GLAZER,[1] VICE PRESIDENT, PJM INTERCONNECTION, L.L.C.

Mr. GLAZER. Thank you, Mr. Chairman. It is always tough to, first off, follow your successor. As bad as August 14 was for me that night, I actually felt good that after 10 years, I said, somebody else is in charge of the PUCO, not me for a change. So I am glad I didn't have his job that night.

I also, Mr. Chairman, I have to tell you, I sleep better at night knowing that we have a member of the U.S. Senate that actually ran an electric system, and not only ran an electric system, but ran it and made it competitive and made the model of competition work. I mean, competition worked in the City of Cleveland. It brought savings to the residential customers and it was used by you as an economic development tool.

I think those lessons are really important, so I just wanted to say thank you for your leadership over the years. It is important that we have somebody in the Senate that actually had hands-on experi-

[1] The prepared statement of Mr. Glazer appears in the Appendix on page 98.

ence, and I think that means a lot as we move forward with this and I appreciate your involvement in this energy bill because it is so important to a State like Ohio.

Let me cut quickly to the chase. I remember one day back in 1996 in the dusty halls of the Ohio legislature talking with the then-chairman of the State Committee, Senator Richard Finan, about this electric restructuring. I remember discussing with him electric restructuring and saying, "If this is about instant gratification, forget it. It is not going to happen. If it is about cutting rates, you don't need to restructure the industry. I have got enough authority at the PUCO to do that right now. If it is about command and control from the government and telling people what to build, we have the authority to do that."

But if we needed to attract investment, when investment is critical to this industry, we need, and I firmly believe we still need, to reform and continue to reform the structure of this industry. The electric industry is the most capital intensive industry other than the military, other than the military, the most capital intensive industry in the world. And right now, we are teetering in a very dangerous place.

And you asked about the provisions of the energy bill. There are good provisions, but there is some language floating around that we think would actually might set this industry back if we are not careful. I think we are in kind of a difficult place and the investors are watching the fact that we are in a difficult place. Let me come to that just in a minute.

I know Dr. Cooper, who I know very well and respect, is on this panel and he is going to say restructuring doesn't work. We should just go back to the old way. Well, as I said, Mr. Chairman, at the beginning, you ran a competitive electric system. You did make it work. By the same token, in PJM, we have actually been able to make the system work on the wholesale level. We have seen greater efficiency in generation. People are better maintaining their equipment than they did under the old regulated system. We have been able to attract new investment. We have been able to keep prices stable.

And what is important for Ohio, in particular, but also for Michigan in this, we have been working with our counterparts in the Midwest ISO on a joint operating agreement and reliability plan. I am not here to say that would have been the total panacea, but it addressed a number of things that went afoul the day of August 14. Had that been in effect, I think we would have certainly reduced the number of people involved. We would have had clearer rules in place.

I think it is important as First Energy moves into the Midwest ISO, which it has chosen to do, as AEP moves into PJM, as it has chosen to do, that we have that agreement in place. I hope we can move forward with the Federal Energy Regulatory Commission, the NERC, the National Electric Reliability Council. It will help Ohio and it will provide a new level of reliability in the Midwest. To the credit of Midwest ISO, we have been working together on that, really had signed that, had that in place, at least conceptually, and we are going through the stakeholder review process.

You had correctly asked, what can Congress do? The first thing I would say is do no harm. There are provisions floating around, because this country is very split on the very issues you are talking about, do we mandate RTOs? Commissioner Kerr will say, my region doesn't need RTOs, and I respect him for saying that. But we run into the law of unintended consequences. There is language floating around in the Senate Committee draft that would really tie FERC at the knees, would ban its efforts on—delay its efforts on standard market design.

Mr. Chairman, I would rather almost kill something than delay something. Delay, frankly, is an easy cop-out, but delay is really the death knell to investment and I am very worried about that.

Also, we heard a lot about investing. You mentioned in your opening statement, invest in transmission. We should do that, but let us do it wisely.

One of the things which we do at PJM, one of the things which, frankly, we did at the PUCO and Dr. Schriber continues to do is regional planning. We ought to not just throw money at transmission. We ought to integrate it with regional planning. Back at the time, we had a big issue, you may recall, about scrubbers.

Senator VOINOVICH. Mr. Glazer, do you want to wrap it up?

Mr. GLAZER. Let me wrap it up by saying, at the end of the day, we need to pause and study what has happened, but we do need to move forward. We need to respect and go at different paces for different regions. But let us not cut the Federal Energy Regulatory Commission at the knees. Let us give it the continued ability to get the job done, and that is in play right now in the energy bill.

Senator VOINOVICH. Both you and Mr. Schriber feel that the legislation, the electricity title, gets the job done, but you are worried about some stuff floating around that would delay it?

Mr. GLAZER. Yes.

Senator VOINOVICH. That is what you are—the language is OK, but you are worried about what is going on inside the Committee?

Mr. GLAZER. Yes, exactly.

Senator VOINOVICH. OK. I have got it. Mr. Torgerson.

TESTIMONY OF JAMES P. TORGERSON,[1] PRESIDENT AND CHIEF EXECUTIVE OFFICER, MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC

Mr. TORGERSON. Good morning, Mr. Chairman. Thank you for inviting me to this hearing. I am Jim Torgerson, President and CEO of the Midwest ISO. I want to provide some insights today on what I saw concerning the circumstance surrounding the power outages of August 14 and offer suggestions as to what might be done in the future.

The Midwest ISO was formed in 1998. It is the Nation's first voluntary regional transmission organization that did not originate from a legislative mandate or against the backdrop of a tight power pool. The Midwest ISO is also the first entity found by the Federal Energy Regulatory Commission to be a regional transmission organization.

[1] The prepared statement of Mr. Torgerson appears in the Appendix on page 111.

The Midwest ISO's region covers portions of 15 States and the province of Manitoba, and our current role is that of a NERC-certified reliability coordinator. As a reliability coordinator, the Midwest ISO monitors flows on key transmission facilities, develops day-ahead plans, conducts next-hour analyses regarding the high-voltage grid, and communicates with the control areas in our regions who have the primary control capabilities to open and close transmission circuits and to redispatch generation.

Three of the more than 30 companies within our reliability territory suffered outages in the blackout, Consumers Power Company, Detroit Edison, and First Energy. The cause of the blackout and why it cascaded will be forthcoming from the work being done by the international task force formed by President Bush and Prime Minister Chretien of Canada. The Midwest ISO only has a part of the data needed to reconstruct those events, and in addition to appearing at today's hearing, the Midwest ISO is cooperating with the international task force and the General Accounting Office in determining what occurred on August 14.

Likewise, the reason for the cascading effect of the outage is unknown at this time. The analysis that has been done to date in the Midwest seems to indicate there were a number of events in the Eastern Interconnection on August 14. Some are surely related to separations and the substantial losses of load that occurred and others are likely unrelated.

At approximately 4:10 Eastern Daylight Time, portions of the Eastern Interconnection were separating from one another——

Senator VOINOVICH. Mr. Torgerson, I know that and I appreciate it.

Mr. TORGERSON. OK.

Senator VOINOVICH. I would really like you to—you have the Midwest. You have seen the language in that energy electric title. Do you like it or don't like it? Do you think they are stepping on your toes? Do you think that utilities should be able to be mandated join? That is what I am interested in.

Mr. TORGERSON. Yes, Mr. Chairman. We find that we need strong reliability standards, and they should be mandatory. We are comfortable with the language in the energy bill. I think it does provide what we need for us to go forward. I think the energy bill, overall, will be satisfactory. I agree with my colleagues here about the energy bill as it stands.

The other thing I wanted to point out is the Midwest ISO has formed an organization, the Organization of MISO States. The Organization is composed of all the State commissions within the Midwest ISO that have gotten together to work cooperatively with the Federal Government on siting of transmission facilities. We believe that approach holds great promise in allowing the siting of needed transmission facilities and protecting the regional efforts to address issues associated with the wholesale electric market.

Senator VOINOVICH. So in terms of the siting of transmission lines, you would be involved in doing that, in other words, setting priorities as to where the transmission lines might be, looking at your grid and how it all works out?

Mr. TORGERSON. In our overall approach, we provide a long-term transmission expansion plan that covers the entire footprint. We just had it approved by our board. We work with all the State commissions in getting this built up. Then we do a review of it to make certain that what is in the plan will relieve congestion. It is not overstepping things, it is making sure there are no duplicative investments, and it looks at how we are solving problems in the Midwest. That is then worked with all the States and the State commissions and then ultimately approved by our board, and our board approved $1.8 billion in investments that needed to be made for reliability in the Midwest over the next 5 years. So those are the things we have been focused on.

Senator VOINOVICH. Do you think that the provisions of the electricity title in terms of siting, dealing with the NIMBY problem and the NEPA problem, are taken care of, or do you still think more is needed. I mean, one of the problems is, how do you pay for it, and two, how can you get it done, and do you think that the language is adequate enough so that if you decide these transmission links have to be sited, that it can be done?

Mr. TORGERSON. We think it is adequate. I think the approach we are taking with the Organization of Midwest ISO States is they are looking at it regionally, but they are also breaking it down. If a project is going to affect two or three States, those two or three States will then work with us on getting the siting done, and that is the game plan behind it. So we think it can be effective.

Senator VOINOVICH. Thank you. I want to make clear also to you, and I again apologize to you, because of this vote schedule, your full testimony will be entered into the record.

Mr. TORGERSON. Thank you, sir.

Senator VOINOVICH. Mr. Museler.

TESTIMONY OF WILLIAM J. MUSELER,[1] PRESIDENT AND CHIEF EXECUTIVE OFFICER, NEW YORK INDEPENDENT SYSTEM OPERATOR

Mr. MUSELER. Thank you, Mr. Chairman. I will skip most of my prepared remarks and go to the subjects that you wanted us to concentrate on here.

Just a brief background. The New York ISO began operation in 1999. We are responsible for operating the grid, assuring open access, and operating New York's electricity markets.

With respect to the policy——

Senator VOINOVICH. May I ask you something? Are you part of PJM?

Mr. MUSELER. No, sir.

Senator VOINOVICH. You are a separate operation? OK. I have got it.

Mr. MUSELER. That is correct. The Northeast consists of—and we all operate approximately the same way. PJM, which is the largest RTO. There are three ISOs, New York, New England, and Ontario. So when we talk about the Northeast, we typically talk about those four ISOs and RTOs which all operate more or less the same way and the markets are—at least the New York, PJM and New England markets are very similar to one another.

[1] The prepared statement of Mr. Museler appears in the Appendix on page 118.

With respect to the policy recommendations, it is certainly strikingly clear that we need mandatory reliability rules. Our view is that NERC should be the standard setting authority under FERC jurisdiction.

You asked, however, whether or not there were—whether or not provisions in the pending legislation are adequate. As you know better than I do, there are differences between the House and Senate versions. For example, with respect to reliability, one of them allows for a region or a sub-region to have more stringent reliability rules if they so desire. We think that is critical. New York City currently has more stringent reliability rules than the NERC rules and we think that if the areas, the States, and the operating authorities believe that more stringent rules are required in certain areas, that we should be permitted to do that.

It would not, in my view, be acceptable to have an area like New York City be held to the floor of reliability when the importance of maintaining power in New York City has effects nationally and even internationally. So we certainly think the legislation deals with mandatory reliability rules very well, but there is a difference between the bills and we think that needs to be taken into consideration.

With respect to siting, again, I think the legislation is very good in that regard. But with respect to backstop authority for siting of transmission lines, there is a difference. So it depends on what the Conference Committee comes up with there. The States have the primary responsibility for siting transmission lines. I don't think anybody disagrees with that and State compacts, State agreements—and PJM is a good example of that in terms of the agreements they have with their States to move on their transmission plans and actually build things—is a good example of that.

However, should the States fail, there, in our judgment, needs to be some backstop to ensure that the public interest is taken into consideration.

Senator VOINOVICH. Mr. Museler, I am going to have to excuse myself because I have got 2 minutes left on the vote, but the point you are making is that if the States don't do the siting and the siting is needed then the backstop should be, what, FERC?

Mr. MUSELER. Yes, sir.

Senator VOINOVICH. FERC should be able to say, these lines have to be sited. We are looking at the big picture. It has to be done.

Mr. MUSELER. Well, they should have the authority to make that judgment.

Senator VOINOVICH. To make the judgment.

Mr. MUSELER. They may affirm the States.

Senator VOINOVICH. OK. I think I will try and be back in about 10 minutes and we will finish up, and then maybe give you all an opportunity to share some more with me. Thank you.

[Recess.]

Senator VOINOVICH. The Committee will come to order.

Mr. Museler, you had some time left. Do you want to make any last one or two comments?

Mr. MUSELER. I would just make one additional point, Mr. Chairman, and that is with respect to the cost recovery, transmission cost recovery provisions in the legislation. It does provide FERC authority for certain cost recovery measures. I would note that I would not suggest anything additional except that even with that authority in States and jurisdictions that have bundled transmission rates and rate caps, the fact that FERC can set a higher transmission rate does not translate into the actual entities—in all cases, it does not translate into the entities actually being able to get that as an incremental amount of revenue recovery.

So FERC needs the authority, in my judgment, to be able to ensure that its incentive rate of returns or its regular cost-base rate of returns actually are able to flow through to the transmission builder-owner within a reasonable amount of time. If there is a 5- or 10-year rate cap that prevents that—that will chill investment if investors know they can't even begin to recover for 5 or 10 years.

That is all I would like to add, sir.

Senator VOINOVICH. Thank you.

Senator VOINOVICH. Mr. Kerr.

TESTIMONY OF JAMES Y. KERR, II,[1] COMMISSIONER, NORTH CAROLINA UTILITIES COMMISSION

Mr. KERR. Thank you, Mr. Chairman. My name, again, is Jim Kerr. I am with the North Carolina Utilities Commission, and to my knowledge, I am the first State official from outside the directly affected region and I appreciate your Committee, Subcommittee's interest in hearing to some extent from those of us beyond the directly affected area.

I have filed written testimony which is part of the record, and given the time constraints will also dispense with my prepared statement this morning. What we have tried to do in our testimony is to describe that we have a very different electric industry structure in the Southeastern United States that is dependent on vertically integrated utilities and a cost-based State regulatory system.

With respect to reliability, I have also illustrated how that electric industry system on a regional level is coordinated through the Southeastern Reliability Council and sub-regions within the Southeast and how we deal directly with accountability, planning, coordination, and operational control.

With respect to the broader issues that are being discussed as possible reactions to August 14, in my testimony, I express the significant concern that regulators in my region have had with mandatory RTOs and standard market design initiatives at the FERC and then try to comment briefly on the discrete issues in the bill which we think, or which I think, as a personal opinion, are pretty good ideas.

You have asked this morning for our thoughts on the specific language that is before the Congress in the Conference Committee, and for the sake of time, I will run through very quickly that it is my opinion that the Federal enforcement authority over reliability standards is certainly an appropriate step that this Congress could take. I believe that appropriate backstop siting authority, similarly, is an appropriate step that this Congress could take.

[1] The prepared statement of Mr. Kerr appears in the Appendix on page 127.

I want to point out here that on that point, I differ with the position of the National Association of Regulatory Utility Commissioners. They are opposed, and I feel obligated to point that out. It is my personal opinion, however, that the language on this issue in the bill is, in fact, appropriate.

I think that appropriate incentives for transmission investment at the Federal level, as they are contemplated in the bill, seem to be appropriate. I am concerned that in January of this year, the FERC issued an incentive rate provision that seemed to me to apply incentives to the moving around of existing transmission as opposed to applying simply to new investment. I think if you apply incentive rates to rearranging the control or ownership of existing transmission as a way to incent folks to join regional transmission organizations, you are creating no new transmission and, in fact, are creating additional costs that will ultimately be borne by the ratepayers.

Finally, with respect to what role the FERC should have with respect to regional markets and RTOs, I think it is imperative that Congress not allow FERC to move forward with mandatory RTOs. I believe that the administration said this morning they were in favor of voluntary RTOs and we believe that should be codified in the energy bill. Market design concepts, market oversight, we believe all of that should be—the various regions of the country should go forward in a voluntary nature so that they can craft those types of solutions to the industry structure that may exist, whether it be in the Midwest, the Northeast, or in our area.

When you ask, am I supportive of the energy bill itself, with the more discrete provisions on siting, reliability standards, investment incentives, that language, as I understand it in the two versions of the bill, seems fine to me.

With respect to standard market design, I am not quite sure what the Senate version is right now. I will tell you that the provision in the Senate, the Domenici substitute, appears to me to be appropriate.

I want to just take a very brief time to respond to some of the concerns raised by the representatives of PJM as well as my colleague, Dr. Schriber, as to whether or not that language—I think that is the language that they were saying would somehow cut FERC off at the knees. As I read Section 1122 of the Domenici substitute, it speaks to no final rule of general applicability within the scope of the proposed SNB rulemaking could go into effect until a certain period of time.

I believe this, and I believe it would be—I read that to mean that if in PJM or if in MISO, that organization, the stakeholders in that organization and the Federal regulators can reach agreement on market design, FERC can certainly approve such a proposal. So I don't believe that language was intended or, in fact, does constrict the ability of my colleagues from other regions of the country to move forward. That is not my intention, and to the extent it might do that, I think that we—and we, in fact, have offered our colleagues from the Northeast and the Midwest to help craft better language, if you will.

So if that was the piece that was referred to as handcuffing FERC's ability to move forward, as I read the actual language, and this is the only language I have seen, I don't believe it does that. I believe it says a rule of general applicability, which I would think would mean a notice of proposed rulemaking that would be applicable across the country.

So with that, my time is up and I thank you for the opportunity.

Senator VOINOVICH. Thank you, Mr. Kerr. Thank you for your perspective. Dr. Cooper.

TESTIMONY OF MARK N. COOPER,[1] DIRECTOR OF RESEARCH, CONSUMER FEDERATION OF AMERICA

Mr. COOPER. Thank you, Mr. Chairman. You have asked us to get to the point and I have got that reputation. [Laughter.]

In my opinion, the deregulation provisions of the legislation go too far and the reliability provisions do not go far enough. Let me first lay out the conditions why and then I will go to the specifics.

Electricity is unique. It is not just a commodity, and we must never forget that. It has no substitutes. It is not storable. It is essential to public health and safety, to daily activities. It is delivered under incredibly demanding conditions that are extremely capital intensive.

And deregulation and restructuring have increased the stress on the grid—so you have to recognize that—by causing a dramatic increase in the number and complexity of transactions for which this system was never built. It creates difficulties in coordination and planning as competition and contracts replace centralized decision making.

PJM was a tight power pool for 50 years or so before it became an RTO. The RTO had nothing to do with its ability to control its area.

Deregulation certainly short-circuited utility incentives to invest in transmission because the private interests of facility owners come into conflict with the shared public nature of the transmission system. It is a highway, not a market, and especially when you are asking them to make investments that they—for a system they share with their competitors. It is very difficult.

And moreover, deregulation undermines the ability to account for social and environmental questions and constraints. The social cost of transmission is much higher than its mere economic cost. The fundamental problem with transmission is not inadequate incentives to invest. Utilities were willing to do so before deregulation. The problem is public resistance to building additional transmission facilities for environmental, health, and safety reasons.

For these social reasons, scarcity of transmission in an economic sense is likely to be a permanent part of this industry's landscape. That is what our people tell us.

The benefits of the shared transmission facilities are difficult to allocate. This is a network that is shared. The problem is geographic and intergenerational. Today's investments deserve a long-term, long-distance transaction, maybe tomorrow's core for serving native load.

Now, I understand the pressure to do something in the wake of the blackout, but when it comes to electricity, doing just anything

[1] The prepared statement of Mr. Cooper appears in the Appendix on page 187.

will not help. You have to do the right thing or you will make matters worse.

Right now, you do not need to repeal the Public Utility Holding Company Act to improve the reliability of the system. I don't need utilities going into non-utility businesses and creative massive multi-state holding companies that escape regulation in order to improve reliability. We do not need to impose the standard market design. And the regional transmission organizations that are embodied in it are the wrong ones to create. They are dominated by industry, they preempt local accountability, and they have forced utilities into markets for allocating transmission resources with no assurances that the capacity is adequate today, additional capacity will be built or maintained.

We must not rely on industry self-regulation. The proposal to move from voluntary self-regulation to mandatory self-regulation misses the point. The difficulty is not the voluntary versus the mandatory. It is the "self" part. We need clear accountability to public authorities.

Do not create private transmission monopolies. Transmission is a natural monopoly, part of a shared network. Transferring control to unregulated companies will simply allow them to increase their profit and exploit their market power.

So that is what you shouldn't do. What should you do? I personally believe we need transmission organizations, but they have to be organized on a very different model than has been contemplated and proposed. Any transmission organization must be based on fairness and public accountability. Fairness requires a process for representation of all interests affected by transmission projects. The way to overcome social resistance to transmission projects is to give people a fair chance to present their case, defend their interest. That is what federalism is all about. It is an ugly, tough process, but it works because it empowers the people.

Accountability demands that the local officials who get the phone calls when the lights go out are the people who are making the decisions, who have the ultimate authority. They didn't call the FERC when the lights went out in Ohio. They called the Ohio PUC. The Ohio PUC must have a fair representation in this process.

Accountability also requires transparency. We cannot have this conflict between the FERC and the DOE and the private companies and the NERC over who has got the data and who is responsible for the analysis.

Finally, even if economic incentives were a problem, and I don't think they are, the solution is not to increase the rate of return but to lower the risk, and that is what the utility model used to do. It established a long-term commitment. It established a stable environment. And frankly, all of the people who say we can't raise money in the industry are living in the dot-com 1990's, not the post-bust market. Give me a stock that offers a stable dividend, a slow and long-term growth rate, the widow and orphan stocks that the utilities used to be. They will have no trouble raising capital. But it is public policy that must create that environment that will promote the investment. Thank you.

Senator VOINOVICH. Thank you. You have all had a chance to hear each other today. One of the things I like to do is to give witnesses an opportunity to comment on what other folks have had to say at the table. If there are any volunteers—Mr. Glazer.

Mr. GLAZER. Thank you, Mr. Chairman. You correctly focused in on the Senate, the legislation, and I think that is clearly the issue. Commissioner Kerr mentioned that there are provisions in the legislation, or being talked about—they are not actually in the legislation—to delay FERC's standard market design initiative. The Commissioner is right. I mean, you can read the language lots of different ways——

Senator VOINOVICH. Standard market——

Mr. GLAZER [continuing]. Design——

Senator VOINOVICH [continuing]. Basically is the overall plan that looks at the entire transmission grid, looks it over and comes back with recommendations on how it can be improved and then tries to determine how individual companies, RTOs, States get——

Mr. GLAZER. It is a plan to actually sort of set forth some standards around the country. One of the big issues was we have seams around the country, and Ohio is a good place, a good example of that. And the idea behind what FERC was trying to do was saying, well, let us have some basic rules of the road. Let the markets look like this. This commodity doesn't respect State lines. Let us have some basic rules with regard to markets, with regard to planning, reliability, etc. So it was a broad brush approach.

Some may argue it was too much, too little. Personally, I am very concerned about a provision that would come down that would just delay things, because as I mentioned, delay is the kiss of death on Wall Street.

Senator VOINOVICH. I think some people were saying delay 3 years or something like that, and my personal feeling is that we have waited too long.

Mr. GLAZER. Exactly.

Senator VOINOVICH. We are so long overdue on this that it is not time for us to delay and look and try to figure out where we are going. What people don't understand is that this is a capital-intensive industry and people are not going to invest in something if there is uncertainty about what the future looks like. They are just not going to invest. It is the same thing with nuclear energy. One of the problems in terms of building new nuclear energy plants is what to do with the waste? That is why Yucca Mountain is very important. We finally decided we are going to go forward with this. So you are going to probably see some new nuclear plants in this country because investors know that that issue is taken care of long term.

Mr. GLAZER. And that is the problem with delay. I would rather, if the Federal Energy Commission comes out with something that the Congress of the United States thinks is inappropriate, you have the tools to change it. When I was on the PUCO, if the legislature didn't like something PUCO did or you didn't like something PUCO did or the Supreme Court, there were lots of checks and balances. But delay is just the kiss of death to investment. I would rather let the FERC move forward. If the Congress doesn't like this provision or that provision, it certainly can weigh in. But delay is the kiss of death for the reasons you stated.

Senator VOINOVICH. Mr. Schriber.

Mr. SCHRIBER. Mr. Chairman, just to underscore what Craig has told you, the one thing that Dr. Cooper said, and maybe the only thing that I really agreed with, is that Ohio should have a voice in the outcome of all this and you are our voice. As Craig has suggested, and I wholeheartedly agree, delay is not the way to go. If there are any provisions that would handcuff the FERC from moving forward, I think it would be very unfortunate.

Senator VOINOVICH. Any further comments?

Mr. COOPER. Mr. Voinovich, I am not sure you want to be responsible when the lights go out and have them call you. Let us be clear. The Chairman of the IO Commission hears about it. The fundamental question here on the SMD was not a question of—there is very little in the SMD that had to do with reliability. The SMD sort of punted on that question. What the SMD has is an economic model for transacting transmission rights and electrons, right, and if the FERC hadn't bothered with the transmission rights, it might have gotten away with its wholesale markets.

But this was a model that two-thirds of the country—let us be clear. You have got Ohio. You have got New York. They have been here. But two-thirds of the States have not chosen their deregulatory model, and in our view, the SMD was coercing the other States in the country through its market design requirements to pursue this path.

So you need to decouple the deregulation issues from the reliability and the transmission issues. If you do that, you will have a lot more support for expanding and devoting more attention to the national highway system for electrons.

Senator VOINOVICH. What you are basically saying is that there are some people that haven't yet decided what they want to do and they shouldn't be forced in it. Your opinion is that the standard Market Design would force them into it. Does anyone want to comment on that? Mr. Kerr.

Mr. KERR. It would absolutely, Mr. Chairman, as Chairman Wood said today, that in this rule, they have moved beyond Order 2000 and said that you would mandatorily be required to join a regional transmission organization as part of the SMD. And again, I think we need to parse words here. Being a lawyer in my former life, I am guilty of that. Delay, I think a lot of mistakes are avoided by taking your time. So, I mean, we can comment generally about whether delay is good or bad.

But as I read the language that came in Senator Domenici's substitute, it says only that FERC shall not issue a rule with general applicability related to the standard market design. What I have not heard, people have said, well, this could delay what we want to do in Ohio. I don't see how that is possible, because that would not be a rule of general applicability if it were confined to a particular RTO or ISO.

If that is true, I think that language could be very carefully improved upon. You could put a "however" clause afterwards. You could say, however, nothing in this section is intended to stop Mr. Torgerson or Mr. Glazer or Dr. Schriber from moving forward in cooperation with the Federal regulators to adopt the market rules that they want to apply within their region.

So again, when I look at the language, I do not see the basis for this agreement, "don't handcuff FERC." In contrast, I know that if FERC goes forward with this rule, its position will be that the entire Southeast and the West and other regions of the country that are in different structures, that have very serious—who have studied these proposals and have continued to have very serious concerns about whether this is correct for us would, in fact, be forced to go forward.

So I don't think it is that our region wants to stop Dr. Schriber's region. We certainly don't. In fact, we would help in any way we could. But I think the question ought to be asked, should your State, should Ohio force upon us what it needs to solve its problems. I think clearly it should not be, and this language allows that because it says you can't put a national plan out, but it doesn't prohibit you from going forward and working maybe with instead of a hammer, a surgical scalpel to work on the various regions to improve upon the systems.

They are doing a lot of good things in the Midwest. They are doing a lot of good things in the Northeast. And what we ought to do is take what is good and improve upon it in every region of the country, but certainly not go backwards in our regions of the country. So with that, I——

Senator VOINOVICH. I would like to get one more comment in regard to what Mr. Kerr said, and I think that what I am going to do is wrap it up with one last comment on what you made reference to, Mr. Kerr, and then we are going to adjourn the hearing.

Mr. Museler.

Mr. MUSELER. Thank you, Mr. Chairman. Just a few comments on that. The first is that there is some regionality from the standpoint of market design. I think that is factored into the SMD rules that FERC wants to promulgate.

Senator VOINOVICH. So you don't think the SMD rules are going to force people, as Mr. Kerr has suggested—or, no, Mr. Kerr. You believe the language is broad enough so that it doesn't force you into——

Mr. KERR. The language in the SMD would, in fact, make our participation in an RTO mandatory. The language—the point I was making is that the language in Senator Domenici's substitute would allow all the regions to proceed as they chose to. So two different documents.

Mr. MUSELER. The point I would like to make is that the standard in standard market design matters. The design of the markets matter. California is an example of what happens when you don't get it right. I am not saying they all need to be the same, but they do need to be consistent and they do need to make economic sense, because whatever the region is, whatever regions choose to say they are the region, there are seams, as Mr. Glazer pointed out, and there needs to be consistency in those rules, both for reliability and for market operation. You cannot have too much diversity in those market rules or you will not have interstate commerce occurring the way it should.

Senator VOINOVICH. Any other comments before I run?

Mr. GLAZER. Just a quick one. I think FERC, we should give them some credit. They really did back down from sort of the more mandatory parts of their standard market design. The rule as it presently is being proposed has that regional flexibility. So I think that they have tried to make the balance between what Mr. Museler said and what Commissioner Kerr would say, so I——

Senator VOINOVICH. Is there anything that FERC can or should do with market design that has enough flexibility to work for all of you?

Mr. GLAZER. I think the white paper that—they just issued what is called a white paper. I think it provides that flexibility in there. They really did hear the message from the Congress. So I think that flexibility is in there. There is this issue about whether you mandate RTOs or not.

The problem there isn't, what if one region, what happens. What happens if one utility doesn't want to play but all the utilities around it want to play? Then you have got a problem. You have got an electrical problem again.

Senator VOINOVICH. There has got to be some provision that says if that kind of thing happens, that somebody is going to step in and make it happen.

Mr. GLAZER. Somebody has got to, right.

Senator VOINOVICH. Absolutely. And I think the other thing that you need to look at is that we are today, tomorrow, 5 years from now, 10 years from now, and God only knows just how this thing is all going to work out, but more and more, we have electricity moving around and I am sure somebody smarter than I am can get into what happened in California. But it really appeared to me that somebody was not doing what they were supposed to be doing in terms of developing a grid so that that situation would not have occurred.

Mr. COOPER. Mr. Chairman, let me offer one point about the seams question, and that gets to the fundamental proposition that—the desire to have a Federal backstop. You have heard it said that the States don't do their job. I want you to do more than that, and here is what I want you to do. I want a formal process, and the Congress ought to take the responsibility for establishing a formal process of State compacts or some other mechanism so that it is not simply a question of whether one State disagreed or not, but a process has to be set up by which the States can sit together and reconcile their differences.

If you look at what has happened in the Midwest, people have jumped in and out. The industry members have jumped in and out. I think the State officials, if they were sitting together with the authority to make that decision, would have done a much better job than the industry has jumping in and out.

So it is a governmental responsibility to make interstate commerce flow effectively, and that is not in anything before the Congress.

Senator VOINOVICH. This has been an interesting panel. I apologize for the interruptions that we have had. Thank you very much.

Again, thank you for your attention and your courtesy in being here, and this hearing is adjourned.

[Whereupon, at 11:32 a.m., the Committee was adjourned.]

KEEPING THE LIGHTS ON: THE FEDERAL ROLE IN MANAGING THE NATION'S ELECTRICITY

THURSDAY, NOVEMBER 20, 2003

U.S. SENATE,
OVERSIGHT OF GOVERNMENT MANAGEMENT, THE FEDERAL
WORKFORCE, AND THE DISTRICT OF COLUMBIA SUBCOMMITTEE,
OF THE COMMITTEE ON GOVERNMENTAL AFFAIRS,
Washington, DC.

The Subcommittee met, pursuant to notice, at 10:07 a.m., in room SD–342 Dirksen Senate Office Building, Hon. George V. Voinovich, Chairman of the Subcommittee, presiding.

Present: Senators Voinovich, Carper, and Lautenberg.

OPENING STATEMENT OF SENATOR VOINOVICH

Senator VOINOVICH. Good morning. As one who has hearing aids, I can understand your problem.

First of all, I would like to say that I am glad that I am Chairman of the Subcommittee on the Oversight of Government Management, the Federal Workforce and the District of Columbia, because this hearing could probably be held in the Environment and Public Works Committee, of which I am also a member. But having the chairmanship of this Subcommittee gives me some authority to oversee different areas of government, and I thought it was very important that we deal with this subject before this Subcommittee on Oversight of Government Management for its significance in terms of the issue as to the public's relying on electricity and also because it is an important issue in the State of Ohio, where a lot of this occurred.

This is the second hearing that we have held on the blackout that hit the Midwest and the Northeast on August 14, and the proper Federal role on managing our electricity system. It is now well-documented that the August 14 blackout was the largest blackout in our Nation's history. Over 50 million people lost power that day, including over 2 million people in Ohio.

What has been lost in the shuffle here in Washington, however, is the impact that the event had on the economies of the Midwest and the Northeast. The Ohio Manufacturing Association estimates that this blackout directly cost Ohio manufacturers over $1 billion, a huge hit that could not have come at a worse time, given that millions of American manufacturing jobs are already at risk.

It is absolutely imperative that we do all we can to prevent such events from happening in the future. As I mentioned at our first hearing on this topic, our Nation is currently served by an overburdened and heavily strained electricity system that was not designed for the widespread wholesale transactions that currently take up a large part of its capacity.

Over the last several decades, our transmission capacity has lagged behind both generation and demand increases. We must take concrete steps now to strengthen our grid by establishing reliability standards that are mandatory and enforceable. We need new investment in transmission capacity, and we need to strengthen existing Regional Transmission Organizations so that we can effectively manage the grid to prevent future blackouts.

A lot has happened since we held the first hearing back in September. First, the U.S.-Canada Power System Outage Task Force that was established to investigate the blackout has issued an interim report entitled, "Causes of the August 14 Blackout in the United States and Canada." Second, a House-Senate conference has reported a comprehensive energy bill that contains electricity provisions which will significantly affect the management of our national electricity system. It is now pending business here in the U.S. Senate, and I am prayerful that it is not filibustered so that we cannot move forward and get it done before we go home.

I want to commend the administration for its leadership on electricity transmission issues and the August 14 blackout. President Bush has moved quickly to create the U.S.-Canada Joint Task Force on the Power Outage, and I appreciate the fact that the Canadians have cooperated and strongly pushed for a more reliable electricity grid in order to prevent future blackouts.

Secretary Abraham has overseen significant changes in the utility sector over the last 3 years—I had an opportunity to talk to him about that yesterday when I saw him—during which time there were two major blackouts. He issued an important study on the transmission grid and created a new Office of Electricity Transmission and Distribution at the Department of Energy. Simply put, the administration has made our national electricity system a national priority—as it should be.

I would also like to comment on the electricity title in the conference report on H.R. 6. Following the August 14 blackout, I, along with several of my colleagues, called on the energy bill conferees to include provisions that would help prevent future blackouts in the conference report. I also asked the witnesses at our first hearing, which was on September 10; Mr. Wood, you were here for that; what they thought we needed to do legislatively in order to prevent future blackouts. Chairman Wood, you probably remember me asking you that question. The response from the witnesses, including Chairman Wood, was that the best legislative fix would be to enact electricity provisions in the comprehensive energy bill including mandatory reliability provisions, provisions to increase investment in the transmission grid, and provisions to grant Federal siting authority to FERC.

The energy bill conferees obviously listened. The electricity title to the conference report will, when enacted, establish mandatory reliability standards that will be implemented and enforced by FERC. It will encourage new investment in the transmission grid. There is a lot of money in there to do that. It will grant Federal siting authority to FERC. And, although it delays implementation of the Standard Market Design rulemaking—we talked about that again at our last hearing—it will allow FERC to strengthen existing Regional Transmission Organizations in order to ensure that problems and mistakes—like the ones detailed in the interim report we are discussing today—are eliminated in the future.

The House passed the conference report by a bipartisan vote of 248 to 160 on Tuesday, and we will be voting on cloture tomorrow morning on this bill. The Senate needs to follow suit and send this critical legislation to the President as soon as possible—it is very important we this done.

As I mentioned earlier, the purpose of today's hearing is to discuss the interim report entitled, "Causes of the August 14 Blackout in the United States and Canada," that was issued yesterday by the U.S.-Canada Power System Outage Task Force. Before we proceed, I would like to include the interim report in the record. Without objection, it is ordered.[1]

I understand that the administration is currently planning to accept public comments on this interim report and then publishing a final report early next year. I intend to hold a final hearing on this topic when the administration releases the final draft and makes its recommendations as to what further steps need to be taken to prevent such an occurrence from happening again, and I would be really interested if any of you witnesses want to comment about whether this conference report contains enough to get the job done? And if you do not believe that it does I would like to know what your ideas are on what other things we need to have in order to give you the tools to get the job done.

We have got an impressive lineup of witnesses this morning to outline the preliminary findings of the task force. I look forward to an informative discussion.

Our first witness today is the Hon. Pat Wood, the Chairman of the Federal Energy Regulatory Commission. And joining him on behalf of the administration is James Glotfelty, the Director of the Office of Electricity Transmission and Distribution at the Department of Energy, a new job, and Michehl Gent is the President and CEO of the North American Electric Reliability Council, and I think that the acronym is NERC. We are very happy to have all of you here today, and thank you for testifying.

Gentlemen, it is the custom of this Subcommittee that we swear in our witnesses, and I wish that you would rise, and I would administer the oath to you.

[Witnesses sworn.]

Senator VOINOVICH. Let the record show that the witnesses answered in the affirmative.

Mr. Wood, we will start with your testimony.

[1] The report entitled "Interim Report: Causes of the August 14 Blackout in the United States and Canada" appears in the Appendix on page 211.

TESTIMONY OF HON. PAT WOOD, III,[1] CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION

Mr. WOOD. Good morning, Mr. Chairman. It is nice to be back. I appreciate the opportunity to discuss the very heavy report yesterday that was presented by Secretary Abraham and Minister Dhaliwal.

Watching and studying the blackout for me, and I think for a number of us, has been a sobering experience. The reliability of the North American electric system is normally so excellent that this year's notable service interruptions from the August 14 blackout here in the Northeast, blackouts overseas in London, Italy, Argentina, Scandinavia, and also and recently back here again from Hurricane Isabel and related weather damages have forced us all to look afresh at all of the old assumptions that we have about the value of reliable electric service and what it takes to keep the lights on.

So here are some thoughts from an energy regulator about what I have learned from this blackout investigation, from the thorough investigation encompassed in the interim report, and from thinking about these other blackouts that we have seen in the past year. The blackouts in the Northeast, in Italy, and in London and elsewhere, have a common theme: Something routine happens, like a tree contacting a power line, or a minor relay setting trips because it was done wrong, and the time to react and keep the system stable suddenly shrinks beyond the capability of human control, when the machines take over.

The grid is a tremendously complex machine, and the interconnectedness that allows us to benefit from both higher reliability and lower costs in all hours also causes the domino failures experienced in many countries in recent months. We cannot ever prevent blackouts, but we can and must learn to reduce their frequency, magnitude and impact.

The best way to manage blackouts is to prevent them, not to hope for heroic rescues when we are already in a jam. And the secret to reliability lies in making sure that every transmission owner, control area operator, and reliability coordinators takes care of the basics: Adequate tree trimming, adequate training for emergency as well as routine operations, effective communications within and across organizations, and having effective backup facilities, procedures and tools.

The investigation clearly shows that had First Energy trimmed its trees, used a solid state estimator program after the trip of the East Lake 5 Unit along the lake, and regularly throughout the afternoon of August 14, and trained its operators to better recognize and deal with these emergencies, the blackout would not have happened. The blackout study shows that the current reliability standards were violated by First Energy and the Midwest Independent System Operator. We need better compliance and tough, clear standards.

The FERC will be working closely with NERC and the stakeholders to develop those standards and to implement the reliability provisions of the energy bill if Congress approves it.

[1] The prepared statement of Mr. Wood appears in the Appendix on page 193.

In anticipation of approval and because the timelines are so short, and the needs are so great, on December 1, the Commission has scheduled a conference to discuss the implementation of the reliability provisions in the statute, in order that we can have mandatory rules in place and operational by this summer. We do need some major investments in new transmission facilities and new grid technologies, especially those that make it easier for us to manage the basics of electricity. But we need to make these investments wisely, for lines and equipment that expand the reliability parameters of the grid where it is needed, for example, new sources of reactive power in the Cleveland-Akron area. These appear to be long overdue.

Further analysis conducted by the blackout investigation teams will teach us much about how the cascade spread, why it stopped where it did, and those things will help us to design a system that, over the long-term, should perform more reliably and cascade more narrowly. The new energy bill offers options to site long-needed transmission lines and to pay for the reliability investments, and I am eager, as my colleagues are at the Commission, to put these measures into place.

We also need to invest in hardware and software that let operators manage the grid more effectively. Tools that improve system monitoring, evaluation, visibility, and information sharing about the grid operations over a wide region will allow operators to manage the grid more reliably on a day-to-day basis as well as in emergencies. Our colleagues at the Department of Energy have done some excellent work in this area over the past few years, and we will be looking to these technologies and others to raise the bar for effective grid management.

Transmission is regulated at both the Federal and the State level. Clearly, we need to regulate it better to assure that the reliability that Americans have come to expect is, in fact, delivered. As the present energy bill recognizes, the days of voluntary reliability standards with no enforcement teeth must end. Federal regulators must work closely with our State colleagues to make sure that utility cost-cutting that allows 14-inch diameter trees to grow in a transmission right-of-way or inadequate operator training or the widespread use of inadequate software ineffectively used must end.

I pledge that my Commission will work closely with our colleagues in Ohio and other States to deliver better regulation for better reliability. I do note with that that my former panelist, Mr. Shriver, from the State of Ohio, announced yesterday some remedial measured that they have initiated with the utilities in Ohio already, with the governor's support.

Some claim that electric competition and higher energy flows caused underinvestment in an overworked grid and made this blackout inevitable. What they ignore is that the operators' primary challenge is to work the system that you have and that the operator has the power to cut back any transaction, whether it is a long distance transaction or one to serve local load; to tighten the operational limits on any transmission line or power plant; and even to cut customer load if that is what it takes to keep the system safe and secure. Markets do not compromise reliability, but we must redouble our efforts to assure that all necessary reliability measures are taken.

Perhaps the saddest portion of the blackout report is Chapter 6, the comparison of this outage to those that have happened since 1965. The common factors are overwhelming: Conductor contact with trees due to inadequate vegetation management; insufficient reactive power; inability of system operators or coordinators to recognize and understand events across the broad, regional system; failure to ensure that system operation was within safe limits; lack of coordination on system protection; failure to identify emergency conditions; ineffective communication; lack of safety nets; and inadequate personnel training.

The seven outages that the report reviewed from 1965 to 1999 include all of these elements. Extensive analysis followed each outage, and blue ribbon panels were developed with good recommendations after each of these outages. Some of the recommendations that have followed these outages have been implemented but not many. It is my hope that with the adoption of the new reliability provisions in the energy bill, we can finally implement most if not every one of these recommendations and stop repeating the mistakes again and again. The cost of the mistakes is high for our Nation, for our sister nation to the north, and all of our citizens deserve better.

The cost of blackouts is immense, both in human and financial costs. I have seen estimates every day that try to impact the cost not only to your home State, Senator, but to the entire Northeastern quadrant of the continent. New transmission facilities and tools are not cheap, and business practices are not cheap, either, but these improved business practices will need to be paid for; they will need to be part of the overall cost of electricity, and as an economic regulator, I am prepared to put those in the rates and justify that is in the public interest.

But if you ask New Yorkers who were stuck in the Subway on August 14 or the Cleveland residents who had to boil their water for days or folks around Maryland and Virginia who sat without power for as long as a week after Hurricane Isabel, most would tell you that they would rather pay a little more for a reliable electric system than reduce their bills to avoid incremental, reliability and improving costs.

So I do think it is important to recognize that there will be a cost to improve this system. I think that it is one that, as a Nation, we should pay, because the benefits far outweigh the costs. But again, as an economic regulator, I do think the findings here were very important and force us all to rethink the paradigm that we have been operating under.

I look forward to your questions, Senator Voinovich and Senator Lautenberg. Thank you.

Senator VOINOVICH. Thank you, Mr. Wood. Mr. Glotfelty.

TESTIMONY OF JAMES W. GLOTFELTY,[1] DIRECTOR, OFFICE OF ELECTRIC TRANSMISSION AND DISTRIBUTION, U.S. DEPARTMENT OF ENERGY

Mr. GLOTFELTY. Thank you, Mr. Chairman and Senator Lautenberg.

I appreciate the opportunity to testify before you today and outline the findings of the U.S.-Canada Power System Outage Task Force investigating the blackout that occurred on August 14.

Three months ago today, large sections of the United States and Canada were still recovering from one of the largest power blackouts in our Nation's history. Since that blackout, hundreds, literally hundreds, of technical experts have worked tirelessly, long hours, sleepless nights, to help the U.S.-Canada Task Force determine how and why this blackout occurred.

Yesterday, as you know, the task force released the interim report that marks our progress to date in the search for answers on what happened that day. The interim report focuses on events, actions, failures, and conditions that led to the blackout and caused it to cascade over such a large region as well as questions relating to the nuclear power plant operations in both countries and the security of our grid control systems. It presents facts collected by the investigation team, and it does not offer speculative or unconfirmed information or hypotheses.

Without going through a line-by-line review of how the system failed, I would like to walk you through the causes that we outlined in the interim report. But before I do this, I would like to make it clear that it is the control area operator, in this case, First Energy, who had the primary responsibility to maintain system reliability, regardless of the conditions. They are required to have the tools to ensure that the grid is reliable. They must be able to take all actions necessary to ensure a reliable system.

With that caveat in mind, I will walk you through the causes that we outlined in our report. The first type of cause: First Energy did not properly assess the changing conditions on their system. They did not use an effective contingency analysis tool routinely. They lost their monitoring alarm systems and lacked procedures to understand that. After they made repairs, they did not check to see if they were effectively working to monitor the system. And once both systems failed, they did not have effective backup tools to ensure that they really had a basic understanding of the system conditions before them.

Second, First Energy failed to adequately maintain its transmission rights of way. This seems so very basic, yet, as Mr. Wood said most of the blackouts that have occurred in this country and overseas, some portion of that or some cause of that deals with inadequate vegetation management in our rights of way. Our report specifically stated: Overgrown trees in First Energy's transmission rights of way caused the first three major 345 line failures in Ohio. These lines trip when contacting trees that had grown past their maximum allowable limits in their rights of way.

Our investigators found that First Energy rights of way being clean are not a new problem. They found one tree over 42 feet tall

[1] The prepared statement of Mr. Glotfelty appears in the Appendix on page 196.

in a right of way that they approximated the age was 14 years old. Another was 14 inches in diameter currently in the rights of way. These trees do not grow overnight. This means that there is a long, systemic issue that needs to be dealt with not only with First Energy, but it needs to be looked at by utilities all across the country on how we ensure our rights of way are maintained.

It seems so very basic that we would maintain our rights of way. However, it does conflict reliability of our system grid with land owner rights, and that is something that the State commissions as well as FERC will have to deal with in the coming months.

The third and final group of causes of this blackout deal with reliability coordinators, in this case, the Midwest ISO. They were unable to provide adequate diagnostic support over the entire region to help First Energy respond to their problems. Their State estimator failed. Their monitoring equipment did not have real-time line status and information. Their operators could not identify where lines had tripped. And the Midwest ISO and their neighbor, PJM, did not have adequate measures to understand issues on the seams between the two borders.

According to NERC and outlined in our report, these failures amount to at least six NERC reliability standards being violated, four by First Energy and two by MISO. Hopefully, the Congress will take action on the energy bill and make these rules mandatory, and we can move down the road to ensuring that we have stiff penalties for violation of reliability rules.

Mr. Chairman, I would like to reference a critical point in this investigation: 3:05 in the afternoon on August 14 is the critical time frame. At that time, the investigation's extensive modeling determined that the system was being operated reliably, within safe operating limits. That fact alone eliminates a number of possibilities as causes of the blackout. It eliminates high power flows to Canada, of which the majority of the power flows going across First Energy's system were actually ending in First Energy's system. Approximately 20 percent of First Energy's load was being imported.

System frequency variations; low voltages earlier in the day and prior days; low reactive power output from independent power producers; outages of individual generators and transmission lines that occurred well in advance of the blackout; all of those were considered by the investigations team, modeled and discarded as not causes of the blackout.

Finally, the task force spent time understanding the nuclear plants and the security of the system. The report outlines that all of the nuclear plants in the United States and Canada shut down safely. They were not a cause of the blackout. They were reacting to system conditions and tripped themselves from the grid. The security group found that there was no terrorism or deliberate cause. There were no SCADA system violations with the information that they have reviewed to date and no computer viruses that caused any of this blackout.

Phase one of our task force investigation and the public's response to it will give us a wealth of information that will be the basis for forming recommendations. Phase two of our investigation will include three public forums in Cleveland, New York City, and Toronto in early December. These forums will offer an opportunity to all of those listed in this report as well as other interested parties to provide the task force with comments and recommendations. The task force will then issue a final report containing our recommendations for improving the electric system and its reliability.

Thank you, Mr. Chairman. I would be happy to answer any questions.

Senator VOINOVICH. Thank you, Mr. Glotfelty. Mr. Gent.

TESTIMONY OF MICHEHL R. GENT,[1] PRESIDENT AND CHIEF EXECUTIVE OFFICER, NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Mr. GENT. Thank you, Mr. Chairman and thank you, Senator Lautenberg. You probably do not know this, but you are my Senator in the State of New Jersey. I appreciate your being here this morning.

Senator LAUTENBERG. I am glad to represent you. It depends on your testimony. [Laughter.]

Mr. GENT. Thank you all for inviting me this morning to speak to NERC's perspective on the interim report of the U.S.-Canada Power System Outage Task Force on the causes of the blackout. NERC, as most of you know, is a not-for-profit organization that was formed after the Northeast blackout in 1965. Our job is basically to prevent blackouts from happening. That cascading outage of 1965 was supposed to have been the last one, and it was not. So this study adequately covers what the problems were leading up to this recent blackout.

We are structured as a regional organization that every electric utility and member that participates in the electric system market belongs in one of 10 regional reliability councils. They own a not-for-profit organization, which is NERC. NERC has been an integral part of the joint fact-finding investigation that led to the interim report that was issued yesterday. We fully support the report's findings and conclusions, and I would like to add that I fully support the testimony of Mr. Glotfelty and Mr. Wood here this morning.

With respect to what happened, the key findings and conclusions may be difficult to find, but I will reference page 23 for the information that Mr. Glotfelty briefly described, and on page 25, you will see the NERC standards that we believe that we have determined have been violated.

Immediately after the onset of the blackout, NERC began assembling a team of the best technical experts in North America to investigate exactly what had happened and why. Every human and data resource that we have requested of the industry has been provided, and experts covering every aspect of the problem have volunteered from across the United States and Canada.

In the week following the blackout, NERC joined with representatives of DOE and the Federal Energy Regulatory Commission to establish a single joint fact-finding investigative team. The question has often been asked: Are there more than one investigation underway? And the answer is no. We stand side-by-side in this.

[1] The prepared statement of Mr. Gent with attachments appears in the Appendix on page 200.

All of the members of the team, regardless of their affiliation, have worked to help correlate and understand the massive amount of data that we have received. We have hundreds of volunteers from organizations all over North America, and we believe more are to come as we venture further into the investigation.

To lead our NERC effort, we established a steering group of the industry's best executive-level experts from systems not directly involved in the cascading grid failure. The steering group's scope and members of that group are described in our Attachment A to our written testimony.

On October 15, I sent a letter to the CEOs of 160 control areas and reliability coordinators across North America that control our electric grids, and I directed them to verify that within 60 days that their organizations are measuring up to reliability requirements in six key areas. Those are also described in an attachment to my written testimony. Those responses are due on December 15. The purpose was to make sure that we are reducing, to the extent possible, the likelihood of any further action like the blackout.

Chapter 6 of the interim report has been mentioned this morning by Mr. Wood. It compares this blackout to blackouts that we have seen in the past, and while it is true that the same things seem to continue to crop up as the reasons, it is also true that we have a number of situations where automobiles were involved in deaths, and we have not been able to stop that. I do not mean to be flip about this, but the area of study is so wide that we are virtually unable to totally prevent these things from happening.

What we have done, though, is we have made tremendous strides. The whole reliability coordinator system is a result of recommendations of a previous blackout. We now certify our operators. That is the result of the recommendations of the report. And we have taken other large steps.

One important step that Congress can take is, as you have indicated earlier, Mr. Chairman, is to pass the reliability legislation or the energy legislation with the reliability language in it. I believe, as you asked, I believe that legislation, the reliability part, is adequate. It will provide us with the assurances that we need to see that the rules are developed correctly and that they are enforced and complied with.

As for the August 14 outage, much remains to be done. As the entity responsible for reliability standards, NERC must understand and communicate with its members what happened on August 14 and why. The interim report is a major step; in fact, it may go beyond a major step. This may be the finest document of its type ever produced, even though it is the result of a disaster. We must also determine if there are other standards that have been violated. We must determine if our standards are adequate. We must make modifications to take into account what happened with this blackout and how the system is now being used.

We will continue to work with the task force. The investigation will proceed, and recommendations will be developed. We expect to learn many more lessons from this event, and I expect that I will be back here again some day in the future.

Thank you, and I would be happy to take your questions.

Senator VOINOVICH. Thank you, Mr. Gent.

We have been joined by Senator Lautenberg. Senator Lautenberg, would you like to make a statement before I start the first round of questions.

OPENING STATEMENT OF SENATOR LAUTENBERG

Senator LAUTENBERG. I would appreciate the chance to just make a short statement. I would like to first welcome Mr. Gent.

And I thank you, Mr. Chairman, for convening this second hearing on the electricity blackout. It takes someone who has been a governor and a mayor, who has been up front with the problem, to recognize the importance of getting on with this thing and not letting it linger, and we appreciate your direction and your action here.

The critical loss of power on August 14 brought a large part of the country to a standstill, and we still have unanswered questions, as all three of you have identified. One of the questions that arises for me is heaven forbid that terrorist organizations that we know threaten us from many, many points and could coordinate something with the lights out would be devastating in terms of not only the damage that might occur but the panic that would follow if news ever got out that there was something underway that was attacking the American people in that area.

This event dramatically demonstrated our vulnerabilities in the Nation's electrical grid and the need for mandatory reliability standards. Now, if we fail to correct the flaws in the Nation's electricity transmission system, experts, they say that other parts of the country will suffer similar blackouts. I think that is a given at this point. Blackouts come with a high price tag: Massive public inconvenience, increased danger for citizens who find themselves in the dark. Reliable electricity is not a new issue.

Some regions have made great progress, while others remain locked in outmoded systems dating back to the beginning of electricity regulation in this country. And I understand that some of my colleagues have concerns about deregulation of the electric industry, but I would like for them to take a look at what has happened in New Jersey, where we are part of PJM, the Pennsylvania, New Jersey, Maryland interconnection, the country's first fully-operating regional transmission, RTO, and the world's largest competitive wholesale electricity market.

And as an aside, Mr. Chairman, I am going to start a society to get rid of acronyms. [Laughter.]

Because by the time we get finished with FERC, NERC, MISMA, MISO, and all of the other things, I do not know whether it is a Japanese menu that I am ordering from. [Laughter.]

And they all get an explanation. So why bother trying to shorten them when we are going to lengthen them by a second statement of understanding?

The ratepayers of New Jersey reaped enormous benefits from belonging to this RTO, including stable rates that have not risen effectively in 11 years. More to the point of this hearing: During the blackout, only 7 percent of PJM's 25 million customers lost their power. Well, it is still a very significant number, but it is a long way from having the 100 percent blackout. And today, that is referred from the witnesses, we want to talk about the need for more

RTOs like PJM, and given the multiple interconnections that exist across the grid, it strikes me that we need some kind of a regulatory structure for regional, not just State or local transmission systems. I do not think that in that forum, it can be handled just by one State or by one community.

So I welcome the release of the U.S.-Canada Task Force Interim Report, and hopefully, it will shine the light—we have not had a chance to examine it yet—but it will shine a light on the events and conditions which led to the blackout. And, of course, because the report was so recently received, we are going to need a little bit of time to fully digest the findings that it contains. And I do not know whether our witnesses have had the chance to read all of the words or every word in it, but we have experienced people, Mr. Chairman, good people who work on these things, and we congratulate you each for your part in that.

And I have talked, the last time I mentioned this, to some of the employees at First Energy who came in to see me, and they complained bitterly about the antiquated state of transmission lines at First Energy. And this was not intended to be a labor dispute. We are not taking sides. But when the people who have to do the work say hey, this facility is outmoded, you ought to pay attention. And so, we did better than we might have, but when we look at the source of the problem, as it seems to be indicated, the source of the problem was where these folks were pointing when we had our conversation.

So, Mr. Chairman, I thank you for the courtesy of letting me make the statement, and I would be happy, after you, to ask some questions.

Senator VOINOVICH. Thank you, Senator Lautenberg.

I guess the new organization decided to get rid of that. [Laughter.]

I would like to congratulate all of you for your testimony this morning and also to underscore the fact that instead of everyone working individually on this investigation, that you have pooled your resources, and we were able to get Canada and the United States to work together on this issue.

As many of you know, there were several other organizations that have taken a look into the blackout and have published reports on their findings, such as the State of Michigan, the Electric Power Research Institute, and the National Commission on Energy Policy, and I would like to enter these studies into the record without objection

One of the things that I support in the energy bill is themandatory reliability standards with penalties. I also support the incentives for utilities to encourage investment in transmission lines, transmission lines are less of a payback than investing in generating electricity. And, of course, the other problem was environmental concerns and not in your own back yard kind of thing.

That is all in the energy bill, and I think was it you, Mr. Wood, who said that you thought we could really move and review and come up with some new mandatory reliability standards, by when?

Mr. WOOD. I would like next summer, if the bill passes. We have 180 days to adopt a rule to set up an electric reliability organization, which could be anybody but could be NERC, and at that point, NERC and anybody else would come in and file to be declared. It is my intention that we basically say when you file, you also file the basic reliability rules. There will probably be some that are controversial that will take time to kind of hash out, but the entity that would be approved here, say, NERC, would design the rules; through their normal, open, transparent process.

Senator VOINOVICH. But the point I am making is you are talking about this summer.

Mr. WOOD. Of 2004.

Senator VOINOVICH. But that is based on the fact that this legislation would be passed now.

Mr. WOOD. That is correct.

Senator VOINOVICH. If it is not passed now, that means we are in limbo until such legislation is passed or this title is pulled out and considered as a separate piece of legislation. Most of us would not want to do that, but it could be necessary if this thing just continues to be in limbo.

Mr. WOOD. Yes, sir. We are assuming, the fact I gave you would be an enactment in the next couple weeks. We would be able to go forward and do the proper open process that the law would require us to do.

Senator VOINOVICH. Second, we talked—you were mentioning about Mr. Schreiber in Ohio heading up the PUCO, the Public Utilities Commission of Ohio.

Mr. WOOD. Yes, sir.

Senator VOINOVICH. You do not necessarily have to do this today, but there are different jurisdictions. In other words, if we pass this legislation, and FERC has a much larger role to play, what responsibilities would the PUCO have in Ohio and other public utilities commissions in other States have. Would they be responsible tree trimming, or would FERC or the organization that FERC would empower to do this?

What is the difference in terms of jurisdictions between FERC, under the new legislation, and States?

Mr. WOOD. Under the new legislation, FERC would approve the standard that NERC would say this applies to either the whole country or to the eastern part of the country, what have you. This is how often you must do the tree trimming, and this is how much clearance you need to give it, etc. This is how you should train operators, backup plans; all the operational.

NERC is also in charge, at the first instance, with enforcing compliance with those regulations, NERC or the ERO certified under the law. If someone complains that they were unfairly treated——

Senator VOINOVICH. Now, we want to make it clear that FERC is not anticipated to do this. You would authorize an organization like NERC or some other organization to go and be involved in this. Is that correct?

Mr. WOOD. Correct, and then, we would be, for example, a court of appeals if someone wants to contest the finding of NERC that they violated a rule, but by and large, that would be handled, at the first instance, by NERC and would not involve either the State or the Federal commission until an appeal is brought before us. So that would actually streamline, I think, the compliance process. Although we could end up handling a lot of appeals; the PUCO would have independent authority under their State law. For example, when I was a Texas regulator, we had independent reliability authority over transmission and over distribution. From my understanding, from what Mr. Schreiber said yesterday, they have clear authority over the distribution side, and they do not over the transmission side.

Senator VOINOVICH. That protocol would have to be worked out, because you have different situations in different States, which I think it would be very important to understand that.

Now, let us talk about transmission lines. It is my understanding that in terms of transmission lines and where they go that that is a State responsibility.

Mr. WOOD. Correct, yes, sir.

Senator VOINOVICH. They are responsible for siting it, correct?

Mr. WOOD. Correct.

Senator VOINOVICH. Now, what if the mandatory reliability organization says that we need a transmission line in order to improve upon the grid, and the States say we are not going to do it? What happens then?

Mr. WOOD. The reliability provisions specifically state that the reliability organization cannot mandate construction of a transmission line or a generation plant. However, another provision in the law, in the proposed law before the Senate today, would empower the Department of Energy, Mr. Glotfelty's group, to identify national interest lines of a national nature, both large lines and multi-state lines. One year after identifying those lines, if a permitting process has not been successfully pursued and a permit received by a utility from a given State or States, then that would elevate up to the Federal Government to look at that. And we call it the backstop siting authority.

So the States are still in the driver's seat. It is only when they cannot act, or they are prohibited by their law from acting, or they choose not to act, that it comes to the Federal Government, in which case, we have to look at the issues you laid out, which are landowner, environmental siting. We might say no as well, but it is looked at on a broader scale and looked at on behalf of what is a national interest line.

Senator VOINOVICH. So from a practical point of view, the reliability standard organization, say, NERC, if they get the job, would say this is really needed. They tell the States about it, and if the States refuse to act, if this was something that they considered to be very essential to the grid, would make that information available to the Department of Energy——

Mr. GLOTFELTY. Correct.

Senator VOINOVICH [continuing]. Who would then review the situation, and a year after that, would come back and say yes, this is absolutely necessary and DOE would be able to take action to get the transmission line constructed; is that right?

Mr. GLOTFELTY. That is possible; we——

Senator LAUTENBERG. May I interrupt just for a minute? I have got to go to another committee, but the record will be kept open so that we can submit questions, I assume, and I would ask our witnesses to respond as quickly as you can.

Senator VOINOVICH. Thank you, Senator Lautenberg.

Senator LAUTENBERG. Thank you very much.

Mr. GLOTFELTY. The process that we would like to go through for identifying national interest transmission corridors is not in place yet. Obviously, that is something that we need to do if the legislation is passed. But we would not wait for NERC or the reliability organization to come to us with information for necessary, needed upgrades. We would do our independent modeling. We would work with the regions to determine national security, economic security or reliability lines that are necessary, and we would designate those in our own process.

It will be a public and open process where everybody can participate. Then, the State will—if the utility agrees and would like to build the line, then, that is when the State process gets triggered. And if they are not completed in a year, the authority would then go to FERC.

Senator VOINOVICH. OK; so the fact is that we are putting incentives in here for companies to go ahead and invest in transmission lines. The State says fine; we will site this, but the utility says hey, we are not interested in going forward with it, what authority would you have in that situation?

Mr. WOOD. Assuming it is identified as a national interest line, that is the trigger. And say there were 50 lines in the country that the DOE puts forward, and all but one of them gets built. If the one does not get built, it can be built also—and this is a provision that was, I think, put in during the conference—it could also be built by someone other than the utility in the area. So you could have what we call a merchant transmission company come in and have the ability to get Federal eminent domain to build as well.

So I do not anticipate that there will just be an absence of anybody willing to build the line, particularly in light of the fact that it has a predictable—it may be a relatively low cash flow compared to what generation used to be. I think I am thinking about a comment that you all made. But it is pretty steady; I mean, 12 percent, 13 percent return on equity, predictable over time, is a lot better than 20 percent 1 year and 5 percent the next year that we have seen on the generation side.

Senator VOINOVICH. So you think it——

Mr. WOOD. It would be an attractive investment, I think. It is steady. I hate to use the term widows and orphans, but it is kind of what traditional utility stocks used to be. This is still a regulated entity. Transmission is actually highly regulated. So it would continue forth in that regard.

Senator VOINOVICH. OK; and the PUCO, the respective State, would be the one that would have the jurisdiction over increasing the rate in order to pay for the transmission line.

Mr. WOOD. Well, as it stands now, in the RTO format, which the Ohio utilities are part of, the rate is actually approved as part of a Federal rate, which the utility can then seek to recover, say it is Cinergy, can seek to recover that in its Ohio-regulated rate. So it is kind of two levels. We set a wholesale rate, transmission rate. We say the transmission rate is X. Then, the company pays for that to all of the other companies that sell transmission. And then, its payment is one cost like income taxes or employee or labor costs or new power plant costs that go into the retail rates.

So it is one that the Ohio commission would have ultimate say on what the total rate is, but the FERC component of that rate is a valid and effective rate in the first place.

Senator VOINOVICH. So you kind of set the parameters of the rate on the national level, and then, it is up to the——

Mr. WOOD. State how they might want to——

Senator VOINOVICH [continuing]. Organization to work with the utility as they traditionally do in terms of their rate-setting.

Mr. WOOD. Yes, sir. They might allocate the cost, for example, to large customers and small customers differently than the next State would do.

Senator VOINOVICH. Senator Carper has joined us, and Senator, I have had a little opportunity here to ask some questions, and Senator Lautenberg was with us for a couple of minutes. And we welcome you.

Senator CARPER. Thank you.

Senator VOINOVICH. And would you like to make some kind of opening statement before we continue the questions?

Senator CARPER. No; I am sorry I missed your questions, though. I would like to ask just a couple of questions.

Senator VOINOVICH. Yes, sure; we welcome you.

Senator CARPER. Thanks very much. And to our witnesses, welcome to this morning's hearing.

As we are gathered here in this hearing room, a debate is going on on the Senate floor, as you may know, on the energy bill that has been reported out of conference. Regrettably, during the conference, the Democrats in the Senate were not invited to participate. And I believe nor were Democrats in the House, and that is regrettable.

And while there are some good things in that energy bill, there are a number of aspects of it that are troubling to a number of us. Today's hearing is, as I understand it, the second of two hearings that are designed to deal with the Federal role in preventing power outages, the likes of which we witnessed in the Northeast and Midwest a couple of months ago.

The energy bill that is before us, specifically the conference report that is before us, lays out a Federal role with respect to transmission of energy, whether you happen to be in our part of the country where we participate in what is regarded, I think, as a very successful grid network. My question of each of you is—and I have not read this report—but I would just like to know when you marry up what your beliefs are what the Federal role should be, and you compare that to what is proposed in the energy conference report, how close are we, how near are we to the mark in terms of where you think we ought to be?

Mr. GLOTFELTY. First of all, the report outlines the causes. It does not have recommendations on how we make our system more reliable. This was just phase one of our investigation. Phase two, which will be done, and we will have a report out early in January, we hope, January or February of next year, will list recommendations that we think are critical for ensuring the reliability of the system.

Most of those, in my mind, will be pretty technical. They will not be broad policy decisions that need to be addressed by Congress.

We think that the majority of the broad policy issues actually have been addressed in the energy legislation before the Senate. First and foremost, mandatory reliability standards are critical. I think all of the witnesses here as well as the majority of the Congress supports mandatory reliability rules and getting them in place as quick as possible.

But we also believe that other parts of the electricity title in the energy bill and in the tax title provide a basis for expanding our transmission system and making it more reliable as well; specifically, siting provisions; tax title provisions, which encourage transmission investment; incentive base rates for transmission investment; all are critical for ensuring that our system maintains reliability and is robust to serve our citizens.

So we believe that it is accurate, and it is a very strong foundation for a reliable system going forward.

Senator CARPER. Thank you. Other thoughts?

Mr. WOOD. Yes, sir, Senator Carper; since I have been at the Commission, I have been involved in the large debate we have had on electricity policy, and I do think certainly, some certainty is called for. We really have been in kind of a stasis now for some 6 years; certainly, the last 8 months. And we cannot really afford to keep going.

So that is kind of a timing issue. As far as the substance, I do think the substance here is good. I think the NERC language, the reliability language, where you would—and this has been, again, kicked around for 6 years—it is time to get it down so we can get rules in place by next summer so that there is true accountability, true enforceability, a much more formal as opposed to informal organization of the reliability enforcement across the country, because it is a multiowner grid that really works as a single machine for the two halves of the country.

To the extent that new transmission investment is required, and this report shows that it is not just a hardware issue; it is a human resources issue, too, but to the extent that investment is required, the incentives that are provided in this bill, which I think are actually progressive; yes, it is not just throwing money at a problem. It has a very strong focus on new technologies that are involved. That was introduced at conference. That was not in the original bill. But the technology angle is one that our Commission has been increasingly adamant on, and to have that kind of support to incentivize and attract the new technologies to bring them out of the lab and into the marketplace and onto the poles and the wires and the systems that make our grid reliable are really, actually, progressive standards.

The siting authority that we have just discussed with the Chairman, clearly, I would rather it never be used; that the States actually handle these siting issues, because I do think that with land owners in particular and environmental issues, the decisions on those should be as close to the people as possible. But to the extent that there are obstacles, either legal or bureaucratic, to getting the needed infrastructure in place, this bill makes it clear that that is going to happen, and those things should be handled on a broader scale than perhaps is being done.

I also think that the bill's strong endorsement for regional grid operators, the RTOs, while not mandatory is a sufficient and quite important provision that this Congress goes on the record supporting competitive wholesale power markets and supports regional transmission organizations and that utilities should join them; it is very important to our Commission. I think there has been a big skirmish over the Commission's desire to make those mandatory, which, of course, I do support but is being put on the side burner for 3 more years.

Well, if in 3 years, we do not have everybody in RTOs anyway, then, shame on us, because this blackout report, our experience with economic efficiencies and Senator Lautenberg's market that he talked about in his comments, which your State also is a part of, Senator Carper, is very compelling, and that story is one that the rest of the Nation is starting to understand as we kind of get past and learn from the California experience about how markets can also be done very wrong.

And finally, when markets are done wrong, this bill provides enforcement and penalties that our Commission has never had before, not only the ability to order refunds for cases the day that they happen but to actually put punitive administrative penalties on top of people who violate the power market rules and violate the law. We have less authority today than the Delaware PUC has. But yet we are intended to be the national regulator. So this bill corrects that as well.

So there is a lot in it. You have other issues on it, but I do think just from the point of view of what you asked me as a regulator for the electricity industry, there is a compelling case to be made for this legislation.

Senator CARPER. Thank you. Mr. Gent.

Mr. GENT. Senator Carper, if I could just add, NERC's only interest in the energy bill is the reliability provisions. We have had consensus on that for nearly 4 years, and I believe that if we had this in place a couple of years ago, we would not have had the blackout. So I would urge you to do what you can to help us out by passing that legislation.

Senator CARPER. OK; in Delaware, we are part of one of those SROs that is called PJM, which we think is a model in some respects for our country. And I guess I am just especially interested in how the provisions of the energy conference report might affect the dependability of the grid, the electric grid, within PJM. We think we have a good system. We like the way it operates, and when we are losing power in a lot of other parts of the country, it is sort of like washed up against our region and pretty much stopped there, and we do not want to mess up a good thing.

Mr. WOOD. Nothing in the bill would impact—and I care a lot about that, too, because it is, from a national perspective, the experience in PJM and now, more recently, in New England, which has adopted a very much close to PJM, the same type of market model and organizational model, just since I have been on the FERC; New York is in the process of probably by March of adopting that same. So you are going to have really the whole Northeast in largely the same format. They are close today; they will be even closer after New York.

We are very interested in that model not only surviving but thriving, and nothing in this bill, in my read or in anybody else's read, would set that back at all. In fact, with the reliability overlay here, I think it enhances it, because it gives not only the economic oomph that we have under current law to back up economic practices and economic decisions, but it now adds that important sister consideration of reliability and says they are both important; they are both enforceable under the national law, and that is the way it is going to be.

So I think that that buttresses, actually, the capabilities of PJM and the other independent operators in the region.

Senator CARPER. All right. Anybody else have a thought on this?

Mr. GENT. For at least 30 years, I have been preaching that we need to have, first, larger power pools, and then, the term was regional transmission organizations, and then, it was ISOs, and now, it is RTOs. Speaking only from an operating standpoint, I think that North America would be far better off if we had a dozen or less of these types of organizations, and certainly, PJM is the all-star model that we would point to in terms of operation.

For my constituents, I have to make it clear I am not proposing the economic operation of PJM, but from a reliability operational standpoint, I think it is stellar.

Senator CARPER. Good. Thank you. Mr. Chairman, could I ask one more?

Senator VOINOVICH. Go ahead.

Senator CARPER. This is a fairly broad question. You have been here testifying. Our Chairman has had the benefit of listening to your testimony. The reason why there are not more of us here is because all of us have three or four hearings going at the same time, and we are just trying to spread ourselves around. Some of us may have a press conference around 12 o'clock that we are looking forward to.

But as I walk out of here, another point or two that you would want me to take along, just say if you remember nothing else or keep nothing else from this hearing, what would that be?

Mr. GLOTFELTY. From my standpoint, I think it would be that this blackout is a reminder that the States and the Federal Government must work together; the economic cost of a blackout of this magnitude is huge. We have smaller blackouts or smaller lines that trip every day across our system, and a renewed focus and renewed attention at the Federal level within the Congress and within the States to ensuring that our system is reliable is actually critical for our economic growth moving forward.

We do, as Mr. Wood said, have tremendous technologies that have been in our labs. Entrepreneurs all across the country are coming to us every day with new technologies that make our system more robust and more reliable. And giving them the opportunity to put those on the system, to make it a more reliable system, is critical moving forward. And the energy bill provides that in our mind.

Senator CARPER. All right, thank you. Mr. Gent.

Mr. GENT. I believe that the legislation, particularly the reliability part of the legislation, provides for a way for the stakeholders to remain engaged and keep their expertise out in front and fresh and involved in the standards-making and enforcement process with a Federal backup when needed. So I would urge you to do something about passing the reliability legislation.

Senator CARPER. All right. Mr. Wood.

Mr. WOOD. I am going to echo my colleagues here on the reliability issue. As a natural gas regulator, too, I do want to point out how critical it is, and this bill does address it, that the Alaska natural gas pipeline project come to be in the next decade. The availability of reliable and environmentally-benign and domestically-produced natural gas is very critical to the overall economic health of our country. We have just seen last year, those prices have actually doubled as supply has come, now, to more of a crunch than we ever thought; that has had a lot of impact on a lot of industries. I know some in your home State and some in mine of Texas as well that are very gas-intensive industries that, if we are looking into the future, $5, $7, or $8 gas when we have our own gas right here in Alaska to bring down and keep the price in the $3, $4, or $5 range, that is a step that has to be taken, and I think it will not be taken unless Congress provides the kind of regulatory, legal, and in the case of the loan guarantees, some financial security for what is probably the biggest engineering project in our lifetime.

The additional increment of liquefied natural gas to that overall mix is very important. These things all, this is where the electricity of the future is coming from. It is coal and natural gas. Yes, there will be nuclear; yes, there will be renewable; yes, there will be more hydro, perhaps, but coal and natural gas are going to be the two big pistons of that engine, and there are provisions in this bill. I know they are not beloved and all, but we have got to step back and think what else do we have? We are not going to put solar panels in space and beam it down like something out of a Star Trek movie. It is going to be coal and natural gas. So we have got to make sure we have got clean coal, and we have got to make sure we have abundant natural gas.

And so, the steps that are laid in this bill to make that happen in the nonelectricity pars of this bill are real important. And I hope that is weighed into consideration by Members of the Senate.

Senator CARPER. When I was first reading the press reports on the conference report of the energy bill, among the provisions that raised my spirits and my hopes were the provisions dealing with the construction of a natural gas pipeline from Alaska. I have since learned that the chairman and CEO of Conoco Phillips, which is the oil and gas company that was believed to be most likely to participate in building a natural gas pipeline to bring natural gas down from Alaska had written to the conferees several weeks ago and indicated what needed to be in the bill in order for them to go forward with the project.

And what his company needed to be in the bill was not included, and he has indicated, as I understand it, that they are not going to go forward with the project.

There were several labor unions, some building and construction trade unions; I think the IBEW was among them; the Teamsters was another labor group that was strongly in support of actually opening up ANWR but also very much in support of the natural gas pipeline proposal. And I learned yesterday that they have withdrawn their support from the bill because it falls short of really making good the commitment to build a natural gas pipeline.

We are still trying to run this one down fully and understand it, but Senator Voinovich and I talked a whole lot about the need for natural gas and our concerns about rising natural gas prices. I was born in West Virginia, and my dad used to be a coal miner for a period of time. I have a whole lot of concern about coal there and other places in the country. We are the Saudi Arabia of coal here in America. And I want to make sure we have access to coal and clean coal technology to use it, and I sure want to make certain that we can bring that natural gas down from Alaska, and I am just troubled by the prospect that maybe we are not.

Senator VOINOVICH. Well, I am glad you brought up some of these other issues.

First of all, I think that we should all feel very good that finally, we are doing something about reliability and mandatory standards. I think in the testimony that you have given that we have had these things happen before, and we just ignore them until the next time, and I think that you should be congratulated, and I think my colleagues in Congress should be congratulated, that we have decided to take this on and do something about it.

My concern is that if this bill is not passed, what are we going to do in the interim period of time? I mean, is there anybody——

Mr. WOOD. I have made a career out of looking at statutory language pretty closely, and I think it would be a challenge, but certainly, this Commission is compelled, in light of what we hear here in this report and what we have learned from participating on the task force that we would push hard to find it in the Federal Power Act somewhere. It is going to be a challenge, and it is going to be hard, but we are going to do our best to go forward under whatever statute we can find. And we are scrambling hard to do that, but I can tell you it is going to be infinitely harder to do it that way than if Congress says we want it this way—do it. But we will commit to trying our best under the Federal Power Act and look in the penumbra of the statute and find it where we can.

Senator VOINOVICH. Well, it would be very important to this Senator and to Senator Carper if you could communicate that to several of the Senators on my side of the aisle and perhaps some on Senator Carper's side of the aisle about how important this is in terms of they may have some problems with other parts of this bill, but if you do not have this authority, you are not going to be able to move forward and deal with this issue that could substantially impact on the wellbeing of their respective States.

Mr. WOOD. I appreciate the opportunity you all have given us today to do that. I know the timing is pretty——

Senator VOINOVICH. Well, somebody ought to pick up the phone. We all know who they are—— [Laughter.]

And try to influence them to say this is important stuff, for this country. The problem here in the Senate is that there is never a perfect piece of legislation, and too often, we let the perfect get in the way of something that is good and moves us down the field, and if it is not as good as we would like it to be, we have another shot at it when Congress comes back.

But in this case, it is not going to be done; then, if it is not going to be done, then, you have got to decide you have got to try to figure out some other way you can get it done. And then, the next thing will be that we pull this out of this bill and then try to get it done next year, and you know how difficult that is going to be.

There was a statement that if—did you make it, Mr. Gent?—the mandatory reliability standards had been in place, and there were penalties—one of you said this—that you believe this would not have happened. I want you to comment on it.

Mr. GENT. Yes; I believe that we have the right standards, but what we do not have now are the rights to do audits, to enforce compliance with the standards. We have been trying for several years on a voluntary basis to get people to agree through contracts to subject themselves to reliability standards. We have been successful in the West of getting three standards agreed to by a wide group of people, and even there, certain companies have refused to sign up and allow themselves to be subjected to mandatory standards.

So we are convinced that the only way we can really do this is to have a law that says you have to do it.

Senator VOINOVICH. And this does get it done for you, with penalties.

Mr. GENT. My general counsel here testified at a recent hearing 2 years ago that it was not a question of if; it was just a question of when, and I think that we can state that again if we do not get the legislation.

Senator VOINOVICH. So again, you really feel that if what is in this legislation was in place, in your opinion, this probably would not have happened.

Mr. GENT. The reliability legislation, yes.

Senator VOINOVICH. All right.

Mr. GENT. That is my opinion.

Senator VOINOVICH. The other thing that I would like—we have identified the responsibilities of the various parties in terms of, in your opinion, the cause of this. The issue is did anything, did the grid contribute to this, were the transmission lines adequate? It is like when we had the stock market crash of 1929, and it went down. And we know that there were certain things that happened. But there was something wrong with the market that allowed it to collapse. And since that time, we have changed some of the things to try to prevent that kind of thing from happening.

We had a crash here, did we not, a big crash? And the issue is is the transmission system inadequate to the extent that it contributed to this at all? Or was it strictly a matter of certain people not doing certain things?

Mr. GLOTFELTY. I will begin that one. I think it is the latter, at least on this example. First Energy and MISO had the tools that were available. They had the responsibility to ensure that this did not happen. The system has worked very well every other day since and every day before.

There were smaller lines that do fail, as we have said, every day. But the system failed that day. And that is not an indictment of the whole region and the transmission lines within that region on any other day. That was just the process and procedures and failures, human, computer and mechanical that happened on that day. Saying that, there probably are transmission lines that can be built in Ohio, around Lake Erie, that can provide more stability to the system, and that is something that I suspect the Midwest ISO and FERC, as well as the Ohio Public Utility Commission, are all considering.

Mr. GENT. But there is another aspect to your question that I would like to address. As we proceed in the investigation, and we take a closer look at all of the things that actually did happen, we may actually decide that we have to redesign some of the ways that we set relays. I hate to get too technical here, but there is a process underway. We might be reaching out too far. We might be tripping too soon or not soon enough. And all of this has to be considered in our committee stakeholders process. It might call for a redesign of certain elements.

Senator VOINOVICH. In other words, if the grid had been more robust, would that have had anything to do with this?

Mr. GENT. I am not sure I can say. I believe that the events, as they transpired, would transcend any robustness.

Senator VOINOVICH. So the thing is that the utilities that were involved in the MISO, when the new law goes into effect, you are going to have the mandatory reliability standards which will put in some discipline into those organizations to do certain things. And then, you will, at the same time, look at the grid to see how that can be also enhanced to make it even more effective in terms of moving electricity and responding to the kinds of things that occurred on August 14.

I just want to say to you that I will never forget that day, because I was coming into Cleveland with my wife, and we were not sure whether the plane would land. We thought that maybe the control tower might not let us in. And then, when we got there, it took us a couple of hours to get our bags, because all electricity was off in the place, and I will never forget it. And then, we were without electricity for 24 hours, which was not too bad, but my daughter and many other people were without electricity for several days.

For the every day citizen, this is a big deal. And I think that sometimes, we take for granted, I know after they had this hurricane here, my staff people were without electricity for 6 or 7 days. And it is very significant. It is a very high priority. Having reliable electricity is important to our quality of life and to our standard of living and also reflective on our economic well being.

And one of the reasons why we have been so successful as a Nation is that we have had reliable electricity at reasonable costs, and it seems to me that if you look at the cobweb and the maze out there of all of the things that the utilities in this Nation are confronted with that we need to streamline the whole process. I think what we are doing here will streamline it; the fact that there are going to be incentives to build transmission lines; that it is going to be a little bit easier to site them and move forward with them is good.

But other issues, Mr. Wood, are very important: Things like new source review that has been kicking around, and finally, the administration has had the courage to take it on and is being criticized, vastly by many of the environmental groups. But utilities were in limbo. They did not know what to do, whether to move forward or not. So they did nothing. It did not make their operations more efficient and did not do anything more to improve in terms of the quality of the environment.

And then, we have the whole issue that has been kicking around here for the last several years in terms of the 4–P bill and how we deal with NO_x, SO_x, mercury and then deal with the issue of greenhouse gases. And I do not think people appreciate the fact that all of these things that are going on make it very difficult for us to get through. It is almost like the Maginot Line, trying to figure out how you can get anything done.

And I would urge all of you in your respective organizations to take a little more interest—I am on the Environment and Public Works Committee, and this hearing could have been held there. But the fact is that we need to start to have a much more global look at—U.S. look at how all of these things connect up with each other and bring some sense and some certainty to a very uncertain environment that we have had for too long. And I think it is really important that we get our environmental groups, harmonize our energy, and our environmental concerns in this country and that we start talking to each other instead of talking past each other.

This is very serious business, and I can tell you right now it is impacting on my economy in my State. You talked about natural gas. We are losing business after business from our State, because they are going—some of them are going overseas because of their natural gas costs are being lowered.

We had a situation where we have done everything we can to close down the availability of natural gas and exacerbate the demand for natural gas. And the prices have skyrocketed. The people have got to understand that that impacts on not only our businesses, our manufacturers, on agribusiness, on the chemical industry; it also impacts on just ordinary citizens: People, particularly, who are what I refer to as the least of our brethren, the elderly and those people, who are poor.

All of this has got to be taken into consideration as we deal with this. And so, I would say to you you have your respective responsibilities, but I think it is also incumbent on you, the Department of Energy, Mr. Gent at NERC, the FERC to start to connect up with some of the other agencies to start looking at the big picture and maybe come back with us and say look, this is what we are going to need if we are going to have an environment where we can provide reliable electricity at reasonable cost and, at the same time, make sure that we protect our environment.

So I want to thank you very much for being here today. We will be back again after the report is finished, and I am interested in that final report, and I think it is important that you give everyone an opportunity that has some issues with it to be heard so that their points of view are recorded there, or they feel like they have had their "day in court." And the next time we get together, I would also, hopefully, this legislation will have passed, and if it has not, then, we will have to decide on how we are going to get this job done together. Thank you very much.

[Whereupon, at 11:28 a.m., the Subcommittee adjourned.]

APPENDIX

Testimony of Kyle E. McSlarrow
Deputy Secretary of Energy
Before the Subcommittee on Oversight of Government Management,
the Federal Workforce, and the District of Columbia,
Committee on Governmental Affairs
United States Senate
September 10, 2003

Good morning, and thank you for inviting me to address the status of the U.S.-Canada Power Outage Task Force investigation into the August 14th blackout, as well as the Administration's views on how we can ensure a more robust transmission system in the future.

It's been just under a month since the widespread power outage that temporarily disrupted life and economic activity in large segments of the northeastern and mid-western United States, and parts of the Canadian province of Ontario. And in that month, we have made good progress in our effort to determine the causes.

Within a few hours of last month's blackout, President Bush and Prime Minister Chretien ordered a cooperative investigation into the incident. Top government officials from both countries – and scores of technical and engineering experts – have been hard at work ever since to determine exactly what caused this outage, how it was allowed to spread to such a large area, and what can be done to reduce the chances of such an incident in the future.

The Task Force is co-chaired by Energy Secretary Abraham and Canadian Natural Resources Minister Herb Dhaliwal. The U.S. members of the Task Force are Tom Ridge, Secretary of Homeland Security; Pat Wood, Chairman of the Federal Energy Regulatory Commission; and Nils Diaz, Chairman of the Nuclear Regulatory Commission. The Canadian members are Deputy Prime Minister John Manley; Kenneth Vollman, Chairman of the National Energy Board; and Linda J. Keen, President and CEO of the Canadian Nuclear Safety Commission.

The Task Force has been working on a number of fronts to collect and assess information on the blackout, visiting power plants and control facilities, interviewing grid operators and utility personnel, and analyzing vast amounts of computer and communications data relating to the incident.

The investigation team is making good progress with the formulation of a timeline of events that led up to the blackout. That detailed sequence of occurrences will serve as the primary framework for piecing together all the facts and events that will lead us to definitive answers about what happened.

The Task Force is gathering and analyzing information on tens of thousands of individual events that happened across thousands of square miles. All that information is being collected, compiled, sequenced and verified so we can be sure that our conclusions are complete, correct and credible.

It's an extremely complex undertaking to analyze and understand all these simultaneous events on such a large expanse of the grid. This outage took about 34,000 miles of our nation's 150,000 miles of high-voltage transmission lines out of service. More than 290 power generation units were tripped off line or shut down. Thousands of substations, switching facilities, circuit-protection devices, and other pieces of specialized equipment were affected, and a very large number of people, policies and procedures were involved.

To expedite the complicated work of sorting through all this, the U.S.-Canada Task Force is organized into three Working Groups focusing on specific aspects of the August 14^{th} outage.

Our Electric System Working Group, led by experts at the Energy Department and the Federal Energy Regulatory Commission along with Natural Resources Canada, is focusing on the transmission infrastructure and its workings and management.

The Nuclear Power Working Group, managed by the Nuclear Regulatory Commission and the Canadian Nuclear Safety Commission, is looking at how nuclear plants in the affected area performed during the outage.

And our Security Working Group, managed by the Department of Homeland Security and the Canadian government's Privy Council Office, is looking at all the security aspects of the incident, including cyber security.

Each Working Group also consists of technical, management and engineering experts appointed by the governors of each U.S. state affected and the Province of Ontario, in addition to the governmental agencies involved in the investigation.

In addition to the Department of Homeland Security, the Security Working Group also includes agents of the U.S. Secret Service and the F.B.I, as well as experts from the Department of Energy laboratories. From Canada, the Security Working Group includes representatives of the Office of Critical Infrastructure Protection and Emergency Preparedness, the Royal Canadian Mounted Police, the Canadian Security Intelligence Service and the Ontario Ministry of Public Safety and Security.

The Nuclear Power Working Group is visiting the U.S. and Canadian nuclear power facilities that were affected by the outage and examining their performance during the incident. So far, the Working Group has been able to determine that all the nuclear plants shut down automatically when power disturbances were detected on the grid – performing exactly as they were designed.

It is a testament to the scale of the event on August 14th that of the 103 nuclear power plants operating across the United States, 70 plants detected some level of grid disturbance but accommodated the fluctuations and remained on-line. All the affected nuclear plants are now all back on-line and performing normally.

The Electric System Working Group has the largest challenge in the investigation because of the sheer size and complexity of the infrastructure. This group, working with technical experts at organizations such as the Independent System Operators from the affected regions and the North American Electric Reliability Council – an industry association formed following a major 1965 blackout to help assure grid reliability -- will be looking at the flow of events surrounding the blackout and determining how they are interrelated. This team also is focusing on the control mechanisms that were designed to keep the blackout from spreading to other areas.

Technical support for the Electric System Working Group is being provided by the Energy Department's Consortium for Electric Reliability Technology Solutions – a group of experts from our national laboratories, and a number of universities, with broad experience in transmission and power delivery issues.

This team, which has investigated a number of major power outages including the 1999 blackouts in the West, includes some of the world's foremost experts in transmission reliability issues, grid configuration, transmission engineering, wholesale power markets, outage recovery and power system dynamics. In addition, we have recruited transmission experts from the Bonneville Power Administration to help in the investigation. These experts led the team that examined the 1996 blackouts in the West.

This group also was instrumental in producing last year's comprehensive National Transmission Grid Study that outlined the requirements for bringing our transmission system up to 21st century standards. These technical and engineering professionals are devoting their full attention to the work of the Task Force to help ensure an efficient and high-quality investigation.

In addition to putting together the timeline and analyzing data from control centers and other sources, our investigators have completed on-site interviews with most of the control room operators of the affected utilities. We hope to complete the first round of interviews very soon.

Once we have determined the causes of the blackout, we will enter Phase 2 of the Task Force's two-part assignment, which is formulating recommendations to address the specific problems we uncover. Any recommendations the joint U.S.-Canada Task Force makes will likely focus on technical standards for operation and maintenance of the grid, and on the management of performance of the grid, in order to more quickly correct the problems we identify.

We are determined to complete this inquiry in a timely manner. We hope to have conclusions and recommendations in a matter of weeks – not months. As Secretary Abraham has said, we will not compromise quality for speed. We want answers quickly, but we want to make sure they are the right answers.

Beyond the investigation of the specific causes of the August blackout and the Task Force's recommended remedies for those causes, there is also the broader focus on the federal role in electricity reliability. Both the Department of Energy and the Federal Energy Regulatory Commission have launched a number of initiatives aimed at making our nation's transmission grid more efficient and reliable.

The President's National Energy Policy noted that one of the greatest energy challenges facing America is the need to use 21st century technology to improve our nation's aging energy infrastructure, which has not kept pace with growing demand or with fundamental changes in our electricity markets.

Since the President's first days in office, the Administration has strongly supported proposals to establish mandatory and enforceable reliability rules to reduce the risk of power outages. We are pleased that both the House and Senate included provisions to establish mandatory and enforceable reliability standards.

The Administration also has supported proposals that would expand investment in transmission and generation facilities by repealing the Public Utility Holding Company Act, which has limited the resources that could be invested in the transmission system by restricting certain types of investors. The Administration supports provisions to advance the development and deployment of new technology necessary to fully modernize the grid, such as higher-capacity power lines and advanced monitoring and communications equipment.

The National Energy Policy also called for the transmission Grid Study that was completed in May 2002. The study outlines the current condition of our transmission system and recommends ways to promote the expansion of overall transmission capacity, elimination of transmission bottlenecks, enhancement of the grid's technical efficiency and improvement of the system's overall reliability.

The Grid Study's recommendations included establishing an Office of Electric Transmission and Distribution at the Department of Energy, which is now helping lead the investigation of the August blackout. The recommendations also include developing new technologies such as superconductivity, which will allow more electricity to be shipped over smaller wires.

The Administration strongly supports measures to provide greater regulatory certainty for transmission expansion, including provisions in the House version of H.R. 6 providing for last-resort federal siting authority for high-priority transmission lines; and providing for the coordination and streamlining of transmission permitting activities across federal lands.

The Administration also supports options that would allow for increased rates of return on new transmission investments, including clarifying that FERC has the authority to provide incentive-based rates to promote capital investment in new transmission and technological upgrades to existing transmission.

We support the goal of regional coordination and planning through the mechanism of voluntary regional transmission organizations that would provide certainty to the marketplace, prevent undue discrimination, and assist in eliminating transmission constraints.

The Administration supports provisions to increase civil and criminal penalties for violations of the Federal Power Act. And we support changes in federal tax law to allow the recognition of gain over eight years for the sale or disposition of transmission assets as part of restructuring and to allow rural electric cooperatives to provide open access to their transmission systems without losing their tax-exempt status.

Investment in our electric transmission system has lagged behind the needs of the marketplace. Action is needed now to help the investment in the grid catch up to the growth in electricity demand and the new requirements of the competitive wholesale power markets, which are saving consumers billions of dollars each year. Private industry and federal, state and local governments must work together to ensure that our electricity transmission system will meet the nation's needs for reliable and affordable electricity in the 21st century.

In addition, government research and development has a role to play. That is why the President's '04 budget request includes additional funding for high-capacity transmission line technologies such as superconductivity and for real-time grid-management tools and other transmission-enhancing initiatives.

Our electric delivery system is the backbone of the U.S. economy. While investing in the necessary upgrades seems expensive, the cost is just a small fraction of the overall economy that it supports. We cannot afford to let such a vital component of our infrastructure fail to meet the nation's growing needs. Thank you for inviting me here today, and I would be pleased to answer any questions.

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Testimony of Pat Wood, III
Chairman, Federal Energy Regulatory Commission
Before the Subcommittee on Oversight of Government Management, the Federal Workforce, and the District of Columbia, Committee on Governmental Affairs
United States Senate
September 10, 2003

The United States-Canada Joint Task Force, with assistance from the Federal Energy Regulatory Commission (FERC or the Commission) and others, is working to identify the cause of the blackout and the steps needed to prevent similar events in the future. Analysis of the blackout is ongoing; the cause of the blackout and the reasons for its broad cascade through eight states and parts of Canada remain the initial goal of the Task Force's efforts.

The federal role in electricity reliability is the focus of this hearing. In the electric power industry, FERC acts primarily as an economic regulator of wholesale power markets and the interstate transmission grid. In this regard, FERC is acting to promote a more reliable electricity system by: (1) promoting regional coordination and planning of the interstate grid through regional independent system operators (ISOs) and regional transmission organizations (RTOs); (2) adopting transmission pricing policies that provide price signals for the most reliable and efficient operation and expansion of the grid; and (3) providing pricing incentives at the wholesale level for investment in grid improvements and assuring recovery of costs in wholesale transmission rates.

The Commission's efforts to strengthen the interstate transmission grid could be further buttressed in the energy bill, now in conference. There are several provisions in the two electricity titles that would do so: a system of mandatory reliability rules established and enforced by a reliability organization subject to Commission oversight; Congressional support for the formation of RTOs across the nation; greater legal certainty for the Commission's efforts to adopt rate incentives for transmission or other investment to alleviate congestion on the grid, including new transmission technologies; tax incentives for transmission owners to join RTOs and to construct new transmission; and, federal backstop transmission siting authority for certain backbone transmission lines, in the event a state or local entity does not have authority to act or does not act in a timely manner.

Testimony of Pat Wood, III
Chairman, Federal Energy Regulatory Commission
Before the Subcommittee on Oversight of Government Management,
the Federal Workforce, and the District of Columbia,
Committee on Governmental Affairs
United States Senate
September 10, 2003

I. Introduction and Summary

Thank you for the opportunity to testify on the blackout experienced in the Midwest and Northeast on August 14, 2003, the current federal role in managing and regulating the generation and the transmission of electricity, and steps to ensure that we do not experience another incident of this nature.

The August 14, 2003 power blackout serves as a stark reminder of the importance of electricity to our lives, our economy and our national security. All of us have a responsibility to do what we can to prevent a repeat of such a blackout. The United States-Canada Joint Task Force (Task Force), with assistance from the Federal Energy Regulatory Commission (FERC or the Commission) and others, is working to identify the cause of the blackout and the steps needed to prevent similar events in the future. While analysis of the blackout is ongoing, it is too early to be sure what caused the blackout or why the blackout cascaded through eight states and parts of Canada.

Even at the start of this investigation, however, this much is clear: our electrical system operates regionally, without regard to political borders. Electrical problems that start in one state (or country) can profoundly affect people elsewhere. Preventing region-wide disruptions of electrical service requires regional coordination and planning, as to both the system's day-to-day operation and system upgrades.

II. Steps Taken by FERC in Response to the August 14 Blackout

FERC staff based in Washington, D.C., and at the Midwest Independent System Operator (MISO) in Carmel, Indiana, have monitored blackout-related developments from the first minutes.

Immediately after the blackout began, FERC staff members went to the U.S. Department of Energy (DOE) to coordinate our monitoring with DOE's emergency response team. At about the same time, FERC staff in the MISO control room began monitoring and communicating the events around the clock until most of the power was restored.

During this time, FERC staff was involved in nearly 20 North American Electric Reliability Council (NERC) telephone conference calls with the reliability coordinators, assessing the situation. These calls also involved close coordination with our Canadian counterparts. Also, the on-site staff monitored other calls between MISO, its control areas, transmission-owning members, and other ISOs and RTOs in their joint efforts to manage the grid during restoration.

In Washington, D.C., FERC staff immediately mobilized to provide relevant information to the Commissioners and to others, including DOE. These communications included, for example, data on output by generating facilities and markets adjacent to the blackout area. FERC also gathered information from ISO and RTO market monitors for each of the ISOs or RTOs in the affected regions. Our staff closely tracked the markets to make sure that no one took advantage of the situation to manipulate the energy markets. Working with the market monitor for the New York Independent System Operator (NYISO), we tracked the New York market especially closely during the period when that market was coming back on line and during the first unusually hot days later in the week of August 18.

Currently, members of the Commission's staff are assisting the Task Force on its investigation of the blackout. The Commission will contribute resources to this effort as needed to ensure a thorough and timely investigation. If any issues arising from the investigation merit specific Commission action, we will undertake such action independently in accordance with our statutory mandate.

III. Background

A. The Current State of the Electricity Transmission Grid

The Nation's transmission grid is an extremely complex machine. In its entirety, it includes over 150,000 miles of lines, crossing the boundaries of utilities and states, and connecting to regions outside our national borders. The total national grid delivers power from more than 850,000 megawatts of generation facilities. The grid is operated by utility staff at some 130 round-the-clock control centers. The large number of these centers – some relatively small -- has been the focus of much attention in post-Blackout analysis and discussion.

When a generating facility or transmission line fails, the effects are not just local. Instead, the problem often has widespread effects and must be addressed by multiple control centers. The utility staff at these centers must quickly share information and coordinate their efforts to isolate or end the problem. Given the speed at which a problem can spread across the grid, coordinating an appropriate and timely response can be extremely difficult without modern technology.

Transmission capital investments and maintenance expenditures have steadily declined in recent years. In the decade spanning 1988 to 1997, transmission investment declined by 0.8 percent annually and maintenance expenditures decreased by 3.3 percent annually. (Maintenance activities include such items as tree-trimming, substation equipment repairs, and cable replacements, all of which affect reliability). During this same period, demand increased 2.4 percent annually.

Transmission is a relatively small part of the overall electric power cost structure, accounting for only 7 percent of a typical end-user's bill. Generation, by contrast, accounts for over two-thirds of the customer's bill. An integrated company, owning both generation and transmission assets, could seek recovery of new transmission investment in its rates. But given that transmission is such a small part of the overall rate, a typical utility is unlikely to file to recover for just new transmission investment, particularly those expansions that may benefit *another* utility's customers.

Even more important than adding transmission capacity is improving the tools available to control center staff for operating the grid. One example is installing state-of-the-art digital switches, which would allow operators to monitor and control electricity flows more precisely than the mechanical switches used in some areas. Installing additional monitoring and metering equipment can help operators better monitor the grid, detect problems and take quicker remedial action. Improved communication equipment can help control centers coordinate efforts more quickly. The level of investment in these technologies has been varied.

B. Today's Regulatory Framework

Currently, there is no direct federal authority or responsibility for the reliability of the transmission grid. The Federal Power Act (FPA) contains only limited authorities on reliability.

For example, under FPA section 202(c), whenever the U.S. Department of Energy (DOE) determines that an "emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy . . . or other causes," it has authority to order "temporary connections of facilities and such generation, delivery, interchange or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest." Secretary Abraham used this authority immediately after the Blackout to energize the Cross-Sound Cable between Long Island and Connecticut.

Under FPA sections 205 and 206, the Commission must ensure that all rates, terms and conditions of jurisdictional service (including "practices" affecting such services) are just, reasonable and not unduly discriminatory or preferential. These sections generally have been construed as governing the commercial aspects of service, instead of reliability aspects. However, there is no bright line between "commercial practices" and "reliability practices."

The explicit authorities granted to the Commission in the area of reliability are very limited. For example, under FPA section 207, if the Commission finds, upon complaint by a State commission, that "any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate or sufficient service to be furnished," and fix the same by order, rule or regulation. The Commission cannot exercise this authority except upon complaint by a State commission.

The Public Utility Regulatory Policies Act of 1978 (PURPA) also provides limited authority on reliability. Under PURPA section 209(b), DOE, in consultation with the Commission, may ask the reliability councils or other persons (including federal agencies) to examine and report on reliability issues. Under PURPA section 209(c), DOE, in consultation with the Commission, and after public comment may recommend reliability standards to the electric utility industry, including standards with respect to equipment, operating procedures and training of personnel.

Since the electric industry began, reliability has been primarily the responsibility of the customer's local utility. Most utilities have been accountable to state utility commissions or other local regulators for reliable service. Typically, the utility keeps statistics on distribution system interruptions in various neighborhoods, inspects the transmission system rights-of-way for unsafe tree growth near power lines, and follows industry requirements for "reserve" generation capability to cover unexpected demand growth and unplanned outages of power plants. Many state and local regulators exercise the authority of eminent domain and have siting authority for new generation, transmission, and distribution facilities.

In 1965, President Johnson directed FERC's predecessor, the Federal Power Commission (FPC), to investigate and report on the Northeast power failure. In its report, the FPC stated:

> When the Federal Power Act was passed in 1935, no specific provision was made for jurisdiction over reliability of service for bulk power supply from interstate grids, the focus of the Act being rather on accounting and rate regulation. Presumably the reason was that service reliability was regarded as a problem for the states. Insofar as service by distribution systems is concerned this is still valid, but the enormous development of interstate power networks in the last thirty years requires a reevaluation of the governmental responsibility for continuity of the service supplied by them, since it is impossible for a single state effectively to regulate the service from an interstate pool or grid.

Northeast Power Failure, A Report to the President by the Federal Power Commission, p. 45 (Dec. 6, 1965).

In response to the 1965 power failure, the industry formed the North American Electric Reliability Council (NERC). NERC is a voluntary membership organization that sets rules primarily for transmission security in the lower 48 states, almost all of southern Canada, and the northern part of the Baja peninsula in Mexico. More detailed rules are prescribed by ten regional reliability councils, which are affiliated with NERC. However, neither NERC nor the ten regional reliability councils have the ability to enforce these rules.

IV. Current Commission Activities

The reliability of the grid can be bolstered through regional planning and operation of the transmission system, such as regional planning of new facilities; greater investment in infrastructure; and better methods of monitoring and managing transmission flow in order to relieve congestion. The Commission has underway several initiatives to address these issues, including: (1) promoting the formation of independent regional organizations with clear wholesale market rules to promote an efficient, reliable wholesale marketplace; (2) authorizing incentive rates for new infrastructure, including innovative technologies; and (3) identifying problems in the transmission infrastructure.

First, with respect to operating the interstate transmission grid, in Order No. 2000, the Commission identified the benefits of large, independent regional entities to operate the grid, and strongly encouraged, but did not require, utilities to join together to form such entities. The Commission noted that such entities would improve reliability because they have a broader, more regional perspective on electrical operations than a stand-alone utility. In addition, some 130 control area operators currently manage the operation of the transmission grid, whereas a smaller number of regional organizations could more effectively manage the grid. Further, unlike utilities that own both generation and transmission, RTOs are independent of market participants and, therefore, lack a financial incentive to use the transmission grid to benefit one market participant.

In Order No. 2000, the Commission recognized that regional organizations also have unique advantages to assist in regional planning for transmission infrastructure. The Commission required that RTOs have a regional planning process to identify and arrange for necessary transmission additions and upgrades. Second, almost half of the electric load in the country is being served by utilities which are part of an independent system operator or RTO. (The major distinction is the size of the entity: an ISO can be smaller than an RTO).

In a July 2002 Notice of Proposed Rulemaking (the Standard Market Design Rule), the Commission proposed to complete the nation-wide transition to independent grid operators, building upon numerous public hearings on best practices in power markets around the world, and also upon lessons learned from market failures in California in 2000. In response to over 1000 filed comments to the rulemaking, the Commission issued a White Paper in April 2003, streamlining the rulemaking effort by identifying the key elements of market design platform for improving the efficiency of wholesale markets. Such a platform would, among other things: (1) promote investment in transmission infrastructure, including new technology and in institutional infrastructure such as regional organization with good market rules and customer protection; (2) provide greater regulatory certainty to make it safe to invest in new transmission infrastructure including new technology; (3) require reliable and efficient management of the use of transmission within the region and between neighboring regions, through day-ahead markets, facilitation of demand response, and the use of price signals.

Second, the Commission has proposed the use of incentive rates to encourage the efficient expansion of the transmission grid. For example, Order No. 2000 recognized that transmission incentives were appropriate for public utilities that joined an RTO and offered various incentives.

In January 2003, the Commission sought to give additional guidance on these transmission incentives by issuing a proposed Pricing Policy for Efficient Operation and Expansion of the Transmission Grid. The proposed incentives would help encourage needed investment in transmission infrastructure and improve grid performance through: an incentive adder for all public utilities equal to an additional 50 basis points on its return on equity for transfer of operational control of transmission assets to an RTO; an additional 150 basis points for sale of transmission assets to an entity independent of any market participant; and an additional 100 basis points for investments in new transmission facilities. The Commission also sought comment on whether incentives for new transmission investment should be structured to encourage the use of new technologies that can be installed relatively quickly (i.e., do not require a long siting process for procurement of new right-of-way, accommodate modular and portable application, and may be environmentally benign). Such technologies appear to offer significant promise of expanding grid capacity, reducing congestion, improving reliability, and enhancing wholesale competition without great cost or delay. The Commission is currently considering comments on the proposed policy statement.

The Commission has also acted in individual cases to provide incentives for development of transmission infrastructure. For example, in June 2002, the Commission approved a proposal to construct transmission facilities to ease the constraints on Path 15 within California. The Commission authorized a premium on return on equity (13.5 percent) and accelerated depreciation for this project as an incentive for construction.

Also, in Southwest Connecticut, an area experiencing significant transmission congestion, the Commission has authorized New England-wide rolled-in rate treatment of certain transmission upgrades and additions that were completed within a specified time period in order to provide incentives for the timely construction of these facilities.

Finally, the Commission has adopted various procedures for identifying areas that need additional investment in transmission facilities. The Commission has conducted a series of regional public conferences to discuss the state of the energy infrastructure within each region, i.e., the West, Midwest, Northeast, and South. We intend to hold public conferences in these regions every year. State officials actively participate in these conferences. These conferences provide a forum for discussing the adequacy of the electric transmission infrastructure within the region, the level of transmission congestion, and potential benefits of increasing transmission infrastructure.

V. What Congress Can Do To Help

Currently, the Congress has before it, in conference, energy legislation which could address a number of issues that have arisen in the debate in the last few weeks over reliability in our wholesale power markets.

First, both the House and Senate bills going to conference provide for mandatory reliability rules established and enforced by a reliability organization subject to Commission oversight. Many observers, including NERC and most of the industry itself, have concluded that a system of mandatory reliability rules is needed to maintain the security of our Nation's transmission system. I agree.

That leads to the question of what entity will be in charge, on a day-to-day basis, of administering the mandatory reliability rules that are developed by the independent reliability authority. In Order No. 2000, the Commission identified the benefits of large, independent regional entities, or RTOs, in operating the grid. (See Appendix for excerpts from FERC Order No. 2000 on reliability benefits of RTOs). Such entities would improve reliability because they have a broader perspective on electrical operations than individual utilities. Further, unlike utilities that own both generation and transmission, RTOs are independent of market participants and, therefore, lack a financial incentive to use the transmission grid to benefit their own wholesale sales.

In the seven years since the Commission ordered open access transmission in Order No. 888, the electricity industry has made some progress toward the establishment of RTOs, entities that combine roles relating to reliability, infrastructure planning, commercial open access and maintenance of long-term supply/demand. The House bill endorses this effort in a "Sense of the Congress" provision. Congress can direct this effort to be completed.

While coordinated regional planning and dispatch are sensible steps to take, we still need to attract capital to transmission investment. I understand that there is significant interest in investing in this industry already; however, to the extent the Commission needs to adopt rate incentives for transmission or other investment to alleviate congestion on the grid, including new transmission technologies, we should do so. While the Commission has recently taken steps in this direction, action by Congress providing more legal certainty on this issue, and in repealing the Public Utility Holding Company Act, can provide greater certainty to investors and thus encourage quicker, appropriate investments in grid improvements.

In addition to ratemaking incentives from the Commission, Congress can also provide economic incentives for transmission development. Changing the accelerated depreciation from 20 years to 15 years for new electric transmission assets is an appropriate way to provide such an incentive. Similarly, Congress can provide tax neutrality for utilities wishing to transfer transmission assets to RTOs.

To the extent that lack of assured cost recovery is the impediment to grid improvements, regional tariffs administered by RTOs are an appropriate and well-understood vehicle to recover these costs. The Commission has accepted different regional approaches to pricing for transmission upgrades, but the important step is to have a well-defined pricing policy in place.

Getting infrastructure planned and paid for are two of the three key steps for transmission expansion. The third step is permitting. States have an exclusive role in granting eminent domain and right-of-way to utilities on non-federal lands. Under current law, a transmission expansion that crosses state lines generally must be approved by each state through which it passes. Regardless of the rate incentives for investment in new interstate transmission, little progress will be made until there is a rational and timely method for builders of necessary transmission lines to receive siting approvals. Providing FERC (or another appropriate entity) with backstop transmission siting authority for certain backbone transmission lines, in the event a state or local entity does not have authority to act or does not act in a timely manner, may address this important concern.

VI. Conclusion

Both FERC and the Congress can take steps to bolster the reliability of our Nation's interstate transmission grid. Taking the steps outlined above can help avoid future disruptions in our electric supply. Thank you.

APPENDIX

Excerpts from Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,092 (2000), affirmed sub nom. Public Utility District No. 1 Snohomish County Washington, et al., v. FERC, 272 F.3d 607 (D.C. Cir. 2002).

Order No. 2000, 65 Fed. Reg. at 862:

Resolving loop flow issues: An RTO of sufficient regional scope would internalize loop flow and address loop flow problems over a larger region.

Managing transmission congestion: A single transmission operator over a large area can more effectively prevent and manage transmission congestion.

. . .

Improving Operations: A single OASIS operator over an area of sufficient regional scope will better allocate scarcity as regional transmission demand is assessed; promote simplicity and "one-stop shopping" by reserving and scheduling transmission use over a larger area; and lower costs by reducing the number of OASIS sites.

Planning and coordinating transmission expansion: Necessary transmission expansion would be more efficient if planned and coordinated over a larger region.

Order No. 2000, 65 Fed. Reg. at 863:

For example, we understand that there have been instances where transmission system reliability was jeopardized due to the lack of adequate real-time communications between separate transmission operators in times of system emergencies. To the extent possible, RTO boundaries should encompass areas for which real-time communication is critical, and unified operation is preferred.

Order No. 2000, 65 Fed. Reg. at 867-68:

The fourth proposed characteristic of an RTO is that it must have exclusive authority for maintaining the short-term reliability of the transmission grid under its control. In the NOPR we identified four basic short-term reliability responsibilities of an RTO: (1) the RTO must have exclusive authority for receiving, confirming and implementing all interchange schedules; (2) the RTO must have the right to order redispatch of any generator connected to transmission facilities it operates if necessary for the reliable operation of these facilities; (3) when the RTO operates transmission facilities owned by other entities, the RTO must have authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards; and (4) if the RTO operates under reliability standards established by another entity (e.g., a regional reliability council), the RTO must report to the Commission if these standards hinder its ability to provide reliable, non-discriminatory and efficiently priced transmission service.

BEFORE

THE UNITED STATES SENATE

COMMITTEE ON GOVERNMENTAL AFFAIRS

TESTIMONY OF DR. ALAN R. SCHRIBER, CHAIRMAN,

PUBLIC UTILITIES COMMISSION OF OHIO

"Blackout 2003"

September 10, 2003

Mr. Chairman, Members of the Committee, my name is Alan R. Schriber. I am the Chairman of the Public Utilities Commission of Ohio and the Ohio Power Siting Board and I am here today to offer a response to the Federal role and response to the Blackout of 2003. I appreciate the opportunity to appear before this Committee, and I respectfully request that the written statement submitted under my name on behalf of the Public Utilities Commission of Ohio be included in today's hearing record as if fully read.

The Public Utilities Commission of Ohio is charged with the duty of regulating the retail rates and services of electric, gas, water and telephone utilities operating within our jurisdiction. Specifically, with respect to electricity, we regulate the distribution of power but not transmission. Additionally, since Ohio has restructured the industry, we no longer regulate generation. We have the obligation under State law to assure the establishment and maintenance of such energy utility services as may be required by the public convenience and necessity, and to ensure that such services are provided at rates and conditions which are just, reasonable and nondiscriminatory for all consumers.

We are all deeply immersed into the factors and events that led up to the outages that occurred on August 14th. I am personally honored to be able to serve on the Bi-National Task Force on the Power Outage, and I am certain causes will be identified as expeditiously as possible. Following that, recommendations as to remedial action will undoubtedly be forthcoming.

To this point, many of the events that took place in Ohio have been documented via timelines. However, the entire picture of what happened August 14th will take serious analysis well beyond the scope of Ohio alone. The effect of the outage on the citizens and businesses of Ohio were documented by Governor Taft before the House Commerce Committee last week. In the aftermath of the outage, the Governor charged my Commission with the challenge of scrutinizing events as they occurred in Ohio and our review will complement those of the Bi-National Task Force.

As we pursue our quest for causes and solutions to the outage, I think we will find that the electrical system in this nation is by no means "third world". It is a very complex, interconnected system that has in fact worked very effectively. The system operated as it was designed to operate on that unusual day in August. Lines tripped, plants tripped, and systems were isolated to prevent further blackouts, just as they were designed to perform. If the systems had not operated as above, not only would the loss of power been far more extensive, but severe damage would have resulted to our infrastructure.

While it is reassuring that the situation was "contained" to some degree, and that remarkable restorations were implemented, we cannot ignore the fact that weaknesses exist that call for repair. Much like the interstate highway system, traffic patterns on the wires have changed, congestion has increased, and wires need to be fixed. Above all, we learned how vulnerable we are, and how dependent we are on our electric system.

You will undoubtedly hear from opponents of deregulation that states such as Ohio that have promoted retail competition collectively contributed to the 2003 outage. I must take issue with this stance. The type of competition that has been promulgated at the state level is one of retail competition, wherein end users purchase their power from marketers who, in turn, buy in the wholesale market. The grid as we know it today has always been the vehicle over which wholesale transactions take place. It was built to accommodate transactions between utilities. This is nothing new.

Nothing has really changed that principle except for the number of wholesale transactions that travel the wires, which is a measure of the overall increase in the demand for electricity. The electrons know nothing except that the quickest way to get somewhere is along the shortest path. Therefore, if you are a marketer in Illinois and buy electricity wholesale from New Jersey, you'll write a check to the generator in New Jersey. However, the electrons that you end up with will come from a generator close by, while the New Jersey generator's electrons will stay closer to home. That is the difference between the contract path and the physical path. All of this is to say that retail deregulation, which has been adopted by less than half the states with a modicum of success, should not be a relevant consideration.

The real challenge that lies ahead, and one that Congress must confront, is molding the electric grid into one that can accommodate the economic realities of today. The reality is that demand has shifted and so to have the suppliers. Parenthetically, one should note that, in the aggregate, generation supply is sufficient to meet demand. The problem is that supply and demand for electricity are not adequately converging through the grid. The reason for this misalignment is a patchwork of overseers of the grid; regional transmission systems, private transmission systems, and systems within the vertical structures of utility companies are accountable to no single boss even though they all interconnect at some point.

If we had many discreet, non-interconnected systems, I suspect we would have more blackouts than fewer, although of less duration, since there would be no interconnected neighbor to help out on a hot day. On the other hand, a regionally coordinated transmission system with a super-large geographical footprint would enhance the ability to work through all kinds of contingencies, some of which are simply beyond the scope of smaller control areas.

Everyone should want to see our transmission resources allocated in an optimal manner. I am prepared to argue that its achievement is predicated on the super-regional transmission system alluded to above. To this end, FERC is the federal agency endowed with the authority to make it happen. Congress should support FERC's efforts to enlist participation by all transmission owners into a regional grid that recognizes the economies of centralized management.

I do not know how many billions of dollars it might take to upgrade the grid, but I do fervently believe that whatever dollars are expended are done so most economically when the needs of the grid as a whole are evaluated as objectively as possible. Given the myopia associated with the fragmented systems of today, dollars may be thrown at "fixes" that often do nothing but add an asset to the utility rate base; not only are the needs of the region ignored, but the utility that has determined to fence itself in does very little at the margin to benefit its own customers. Regional approaches must be adopted to appreciate the needs and recognize the benefits.

An independently administered regional transmission system, on the other hand, could prioritize its investments based upon marginal benefits. Dollars would flow to the points on the grid that would yield the most benefits, for example, the amount of regional congestion that is relieved, regardless of whose "backyard" it resides. Why would a single state permit the construction of a high tension wire within its boundaries if there were not a single "drop" along the way? The answer would be that it probably would if it understood that the congestion relieved by the line significantly increased the level of unobstructed power flows within the state. The problem is in the "understanding". The manager of an independent, integrated, profit maximizing transmission organization understands the resource optimization process because it has the bigger picture.

In addition to rational planning, the aggregated grid system is also more likely to attract capital. Investment dollars move to the places where the potential yields are the greatest given the risks. We might conjecture that the greater the number of electrons that flow, the greater the dollars that flow to the construction of wires that carry those electrons. A unified super-regional grid maximizes power flow through the grid and should be politically indifferent as to the points of need located within. In contrast, sub-optimal investments in electric facilities are made when a single entity, without regard for the region around it, is more interested in closing itself off from the greater good. Those who provide the dollars are more likely to follow the path of investment with the greatest potential for risk/return optimization, which from my point of view resides with the regional grid.

One great challenge to enhancing the system is the ability to site large transmission lines across states. Large towers with conductors capable of carrying hundreds of kilovolts are generally not a welcome sight in most areas, and resistance to their construction is something that we'll live with indefinitely. The authority to site power lines today lies with the states, and therein lies a source of debate for the Congress.

Arguments break both ways with respect to federal-versus-state siting. Most states stand firm in their belief that power siting is strictly a state issue, and some good arguments are made on their behalf. First, the state decision-makers know their constituents. They are most familiar with the local contacts that so often weigh in on siting issues. Second, the speed at which certificates are granted most certainly exceeds that accomplished under federal jurisdiction; our experience with pipelines underscores the point. Finally, state officials will bear the brunt of unpopular decisions regardless at what level those decisions are made.

In Ohio, the legislature has given the Power Siting Board, which I chair, broad powers. Affected parties are afforded hearings, and certificates are granted only after a extensive range of issues are examined. These include environmental, health, agricultural, and others. Our siting process compels us to take into consideration the effects on the region, not just the state. All told, Ohio is among the most progressive states in getting utility facilities up and running.

Unfortunately, other states do not move swiftly as does Ohio in siting electric or pipeline facilities. Furthermore, some states are dominated by Federal lands. As a result, some argue that federal preemption of state siting decisions is appropriate. In a series of meetings under the auspices of the National Governors Association, it was decided that, at least in the Midwest and the East, states could agree to work together to site interstate transmission lines. As a compromise, the Electricity Title of the Energy Bill under consideration provides that the FERC shall provide a "backstop" in the event of a recalcitrant state. This is a logical, progressive outcome.

I have been talking to this point about the physical conditions that bind the grid for better or worse. However, the economics of all of this must not go unmentioned. Different transmission systems, as fragmented as they might be, often employ pricing strategies that are inconsistent with one another. When the price of moving electricity a number of miles across different operating areas varies according to whose area is being crossed, the outcome can be quite confusing for those paying the freight. Without belaboring the point, another strong argument that favors super-regional management of the grid is pricing consistency and the concomitant higher level of economic certainty conferred upon users of the grid.

This aggregation of transmission systems or control areas is the cornerstone of the FERC's endeavor. To be thoroughly effective, however, it must also draw lifeblood from Congress as Congress deliberates its Energy Bill. It is antithetical to our interests to delay FERC's attempt to implement its design for a rational transmission market.

If Congress must do any one thing immediately, it must address the issue of system reliability. While the states have the authority from their legislatures to set and enforce rules for distribution systems, the federal government must confer power upon someone to do the same for the transmission system. Whether it be the North American Electric Reliability Council (NERC) as currently proposed in the Energy Bill, or whether it be the FERC, the rules of the road must be mandatory. Once in place, the enforcement of the rules can follow the course taken by other federal agencies.

A unique and efficient means of enforcement of some federal rules has evolved over the years. Ohio, as well as other states, undertakes a number of such tasks on behalf of federal agencies. For example, the US Department of Transportation has very specific rules that speak to natural gas pipeline safety. Ohio's Public Utilities Commission receives funds from USDOT to inspect and enforce those rules within the state's borders. Ohio also participates in the inspection protocols for the transportation of hazardous materials. The same process has evolved with the Federal Railroad Administration which has prescribed rules for rail crossings. The Ohio Commission has personnel evaluating and prioritizing grade crossings for the purpose of supporting communities with safety devices. Given the fact that Ohio and other states already support federal agencies in rule enforcement, does it not make sense to consider the same for the transmission of electricity?

The events of the past couple of weeks speak clearly to the need for Congress to do two things. First, Congress must focus on endowing some agency or organization, e.g., the FERC or NERC, with rule-making authority that locks-in our quest for a reliable grid. Second, it must enable the FERC to move forward in its initiatives to bring about a physically and economically rational structure and governance to the transmission system.

I appreciate the opportunity to have appeared here before you today and look forward to clarifying anything that I have said.

EXECUTIVE SUMMARY OF TESTIMONY OF CRAIG A. GLAZER, VICE PRESIDENT, GOVERNMENT POLICY, PJM INTERCONNECTION

In his testimony before the Senate Subcommittee on Oversight of Government Management, the Federal Workforce and the District of Columbia, Mr. Craig A. Glazer, Vice President, Government Policy for PJM Interconnection detailed a "road map" for Congressional action to strengthen the interconnected transmission grid and to meet customer needs for reliable service and stable prices. Mr. Glazer outlined this road map in the context of the outage events of August 14, 2003.

Mr. Glazer points out that the events of August 14, 2003 represent as much a crisis in confidence in the industry as it does a failure of the electric power grid. He notes that the outage of that day, although requiring critical study and analysis, must not paralyze the industry from moving forward with critical reforms. "We must learn from the positive experiences as well as the negative ones facing this industry and craft rational common sense rules that follow and respect the laws of physics which govern this speed of light product" Mr. Glazer stated. His testimony details the value of regional coordination and notes that we cannot continue using outdated solutions to meet the 21st century needs of customers. He details a road map for Congressional legislation which includes the following points:

1. Provide FERC with the authority it needs to ensure that regional organizations can flourish to plan and manage the grid in a coordinated manner;
2. Do not discourage or strip FERC's authority to move forward in those regions of the country that wish to move forward with the development of competitive markets;
3. Ensure that the laudable goal of protecting native load does not work to repeal the anti-discriminatory provisions of the Federal Power Act or to otherwise balkanize the grid. A clear statement from Congress that native load should be protected but flexibility in how that native load is protected would ensure this proper balance;
4. Whether federal or state siting is preferred, encourage regional planning processes, undertaken by independent RTOs with state and stakeholder input, before the power of eminent domain is exercised to appropriate private property to build transmission.

5. Reliability standards should be made mandatory, with their development and enforcement overseen by a public body. Deference should be provided to regional solutions that improve reliability for the region and for neighboring systems.

Mr. Glazer points out that much of the PJM system was spared from the effects of the August 14 outage as a result of protective hardware, on PJM and neighboring systems, acting as it was designed to protect equipment and isolate the disturbance. The operation of these protective relays had the effect of separating much of the PJM system from the surrounding grid and thus avoiding much of the blackout's impacts except in Northern New Jersey and in the Erie, PA. area. Thereafter, PJM system operators worked to rebalance the system and begin the process of restoration both on the PJM system and by providing assistance to neighboring systems in Ohio and New York.

Although much of the protection of the PJM system occurred automatically, Mr. Glazer explains that PJM's independent regional planning process has been a critical element to designing a system which can both support an interconnected grid but also withstand an outage of this magnitude. He details the work that is underway collaboratively by PJM and the Midwest ISO to develop a Joint Operating Agreement and reliability plan which will provide a much higher level of coordination and communication among control areas in the Midwest than exists today upon the integration of the Commonwealth Edison system into PJM. Finally, Mr. Glazer urges Congress to encourage the development of such independent planning protocols and link them to any incentives it provides for the construction of transmission in order to ensure that transmission construction and the use of the power of eminent domain is undertaken wisely and judiciously.

TESTIMONY OF CRAIG A. GLAZER
BEFORE
SUBCOMMITTEE ON OVERSIGHT OF GOVERNMENT MANAGEMENT, THE FEDERAL WORKFORCE AND THE DISTRICT OF COLUMBIA COMMITTEE ON GOVERNMENTAL AFFAIRS
UNITED STATES SENATE
SEPTEMBER 10, 2003

Mr. Chairman and Members of the Committee:

The events of August 14, 2003 represent as much a crisis in confidence in this industry as it does a failure of the electric power grid. As one who has worked in this industry my whole professional life, I am vitally concerned that we restore the public's confidence by establishing a clear road map to move this industry forward. Of course, time needs to be taken to ensure careful analysis and the development of solutions which can be tested and retested prior to full scale implementation. And although thoughtful reflection is needed, we simply cannot allow the events of August 14 (as significant as they were) to paralyze us from moving forward.

None of us can repeal the laws of physics which ultimately control the behavior of this speed-of-light product. As a result, policymakers need to drive rational public policy, market development and infrastructure investment which free this industry from mountains of red tape, constant political and legal battles over individual proposals and never-ending regulatory proceedings over Regional Transmission Organization ("RTO") formation. These solutions also need to meet the interstate and international nature of this speed of light product. As a result, although I will spend part of my testimony addressing the specific questions you raised concerning the August 14 event, I want to lead with what I think is the far more pressing issue: How do we address the critical crossroads we find ourselves in today? How does Congress, as our nation's policymaker, moves this industry forward through clear and coherent policies and institutions? How do we avoid the pitfall of unclear or internally contradictory policies slowing industry growth and discouraging need investment?

To answer these questions, we can look at real facts and analyze the positive as well as negative experiences faced by this industry. The "bottom line" is that certain models of deregulation and restructuring of the industry have worked and have developed real value for the customer. It has been proven that restructuring and deregulation can work to provide real benefit to customers in the form of stable prices, increased generator efficiency and new demand side options for consumers. Although not necessarily the answer to the events of August 14, market rules and procedures can work to limit the adverse impacts of transmission or generation outages triggering larger events. And as a result of our transparent and independent regional planning process, the PJM system was designed to withstand and did withstand, for the most part, an outage of this magnitude. So as we move the industry forward, we must not throw out the baby with the bathwater or tie the hands of the regulator to move forward based on the positive experiences that have occurred during this otherwise troubled time.

Much of the mid-Atlantic region's ability in real time to withstand the disturbance of August 14 was the result, not of human intervention, but of hardware working as it should----hardware that was designed to protect each of our systems from outside faults, voltage drops and other system disturbances that threaten system stability. This system runs from the Delaware short to Washington County, Ohio. But in the longer run, a transparent planning process undertaken by an independent entity such as a regional transmission organization with a "big picture" look at the entire grid, can ensure that the appropriate hardware is in place and that reliability is maintained proactively and at prudent cost to the consumer. And important market tools such as ordering redispatch of generation between neighboring systems, something which PJM and the Midwest ISO have put forward as a reliability solution in the Midwest, and which PJM and the New York ISO are piloting between their systems, can help alleviate the adverse impacts of curtailments of individual transactions. Only independent entities such as RTOs can undertake these solutions in a manner which will not be seen by the marketplace as favoring one provider over another or sacrificing one entity's "native load" at the expense of another's "native load".

Just as Abraham Lincoln stated that "a house divided cannot stand", neither can an industry continue to rely on unchanged 20th century institutions and tools to police the new 21st century world surrounding this speed of light product. Today we find ourselves teetering somewhere in between a traditional and restructured environment. This is a highly unsustainable state and cannot help to either improve reliability or attract needed capital for investment. Let me give an example.

The Energy Policy Act of 2003 provides for incentives for the construction of vitally needed new transmission. Such investment is extremely important and Congress should be applauded for taking this bold step. However, in the same breath, there is discussion of adding provisions which would limit or suspend FERC's ability, through rulemakings, to create the very institutions needed to independently and in an unbiased manner, plan the right location for this new investment. Absent a rational planning process undertaken by an independent entity such as an RTO, one that balances the need for generation, transmission and demand side solutions simultaneously, we risk building transmission in the wrong place and appropriating private property for investments that don't necessarily solve (and in some cases create new problems) for the regional grid. In short, if we are not careful, without the proper tools in place, we run the risk of creating tomorrow's stranded investment and simply throwing ratepayer money at the problem. By contrast, regional planning processes undertaken in an unbiased public process, allows the marketplace to obtain the needed information to effectuate the wise choice between transmission, generation and demand side solutions to meet our reliability and economic needs. The states in the mid-Atlantic were extremely wise during PJM's formation---they insisted that before any markets are started that the RTO have in place a regional planning protocol. They correctly noted that as we are talking of using a power, which only the government can grant, to appropriate private property, we ought to ensure that we are exercising this powerful government authority both wisely and judiciously. An unbiased regional planning protocol can do just that.

For all these reasons, we recommend that Congress undertake the following steps:

i. Provide FERC with the authority it needs to ensure that regional organizations can flourish to plan and manage the grid in a coordinated manner;

ii. Do not discourage or strip FERC's authority to move forward in those regions of the country that wish to move forward with the development of competitive markets;

iii. Ensure that the laudable goal of protecting native load does not work to repeal the anti-discriminatory provisions of the Federal Power Act or to otherwise balkanize the grid. A clear statement from Congress that native load should be protected but flexibility in how that native load is protected would ensure this proper balance;

iv. Whether federal or state siting is preferred, encourage regional planning processes undertaken by independent RTOs with state and stakeholder input before the power of eminent domain is exercised to appropriate private property to build transmission.

v. Reliability standards should be made mandatory, with their development and enforcement overseen by a public body. Deference should be provided to regional solutions that improve reliability for the region and for neighboring systems.

With this overview in mind, I will proceed to address some of the questions that have arisen concerning the outage of August 14:

1. **What exactly were the specific factors and series of events leading up and contributing to the blackouts of August 14?**

2. **At what time did your company first become aware that the system was experiencing unscheduled, unplanned or uncontrollable power flows or other abnormal conditions and what steps did you take to address the problem? Were there any indications of system instability prior to that time?**

3. **Which systems operated as designed and which systems failed?**

Answer

As noted above, the location, character and proximate cause of the initial disruption in the transmission and supply of electricity is the subject of an ongoing NERC/DOE investigation and PJM defers to that investigation. As a result, PJM will limit its response to actions it took on its own system both prior to and during the August 14 outage.

As to its own system, PJM first became aware of a disturbance on the Eastern Interconnection at about 4:10 pm on August 14th. Prior to that time, August 14th could be characterized as a typical unexceptional summer day in the PJM control area, with a typical number of lines out of service, and relatively few scheduled or unscheduled outages. At noon on August 14th, NERC initiated a routine time frequency correction across the Eastern Interconnection in accordance with NERC operating policies, because the time frequency had exceeded its margin for error. PJM was properly following the NERC standard process, but it is mentioned in this context because it accounts for a frequency fluctuation in PJM data at the time the correction was implemented.

PJM became aware of significant impacts on its system from an external disturbance at approximately 4:10pm. At the time of the disturbance, PJM recordings of telemetered load and frequency revealed an initial loss of more load than generation on the PJM system. Subsequently system operators reduced generation output in order to bring the system back into balance. PJM experienced a loss of load of approximately 4,500 MW of its total load of approximately 61,200 MW at the time of the disturbance. About 4,100 MW of PJM's lost load manifested in northeastern New Jersey, while an additional 400 MW of load was lost in northwestern Pennsylvania near Erie.

The disturbances noted by PJM at approximately 4:10pm resulted in some individual units going off-line in PJM and in transmission lines opening. The cascading effect of the outage caused PJM to lose approximately seven percent of its load, but automatic relay devices deployed throughout PJM in accordance with our design and planning criteria isolated most of the PJM footprint from the power loss. Automatic relay devices effectively isolated most of PJM from Ohio and New York, which were subjected to prolonged outages. By 4:12pm., most of the tripping of generating stations and transmission lines within PJM had subsided. Thereafter, PJM system operators worked to rebalance generation and load within the PJM system by reducing system frequency to a normal range. In addition, PJM system operators initiated procedures for more conservative operation of the system, to assure that system restoration could proceed more effectively. The disturbance itself played out over the course of mere seconds – with no real-time human intervention possible – but system operators played a vital role in system restoration.

In summary, the system worked as it was designed---through the automatic operation of relays PJM was able to isolate problems which effectively separated it from the outage and "kept the lights on" for the overwhelming majority of its customers. Through swift operator action, PJM was able to stabilize its system and also provide critical support to the restoration efforts in Northern New Jersey and Northwestern Pennsylvania, as well as the neighboring systems in the New York, and Ohio.

4. If events similar to those that occurred on August 14, 2003 had happened a year ago, would the results have been the same? If similar events occur a year from now, do you anticipate having to place

equipment and processes sufficient to prevent a reoccurrence of the August 14 blackout?

__Answer__

Prior to the August 14 outage, PJM and its Midwest counterpart, the Midwest ISO had just reached agreement on an historic Joint Operating Agreement and Reliability Plan that, if implemented, would bring a new level of coordination and data sharing that would clearly have avoided some of the communication and coordination problems that arose in the context of the August 14 outage. The Joint Operating Agreement and Reliability Plan provides for an unprecedented level of coordination and data sharing among neighboring systems in the Midwest. The Joint Operating Agreement detailed monitoring measures and specific actions that each of the large RTOs would take to clear congestion or reliability problems on the other's system. at key designated flowgates. It would provide for actions that presently do not occur systematically in the Midwest including:

- day-ahead and real-time monitoring of each RTO's system;
- detailed data exchange between the two RTOs;
- emergency operations protocols;
- joint planning protocols; and
- mandatory redispatch of each other's generation in order to relieve congestion on the other's system.

This Agreement, coupled with the fact that there would be just two entities, both with planning responsibility and a large regional look as opposed to multiple control areas with a more limited view of neighboring systems, would provide for an increased level of reliability in the Midwest and would reduce the coordination and communication issues that exacerbated the problems which occurred on August 14th. The Joint Operating Agreement and associated reliability plan were undergoing stakeholder review at the time of the August 14th outage. Subsequent to that time, both PJM and the Midwest ISO have committed to reviewing the document in light of lessons learned from the August 14th outage and providing appropriate enhancements. PJM looks forward to review and comment by the respective stakeholders and state commissions in the area.

That being said, PJM believes that should the Joint Operating Agreement and Reliability plan be allowed to move forward it would provide a model that has been sorely lacking in this nation relative to coordination and communication between two large regional entities each charged with the responsibility of ensuring reliability of the regional transmission grid.

5. What lessons were learned as a result of the blackouts?

6. How can similar incidents in the future be prevented?

Answer

As the DOE investigation to the causes of the blackout is first beginning, it is too soon to detail with specificity all of the "lessons learned" from the August 14 event. That being said, there are some overarching lessons of August 14 which played out dramatically in how different entities reacted:

We cannot continue to use 20th century solutions to solve 21st century problems--- In the last century, reliability was ensured through a series of loosely described emergency support agreements among neighboring utilities. No regional planning process existed and each individual utility was charged with maintaining and planning for the reliability of its individual portion of the grid. Although regional reliability councils exist to coordinated regional efforts, such entities were neither independent of the market participants nor empowered to require solutions and order penalties. It is clear that these loose agreements and institutions of the last century will not work in the future. Rather, we need Congress to:

i. encourage the development of regional transmission organizations and not strip or suspend FERC authority to undertake necessary generic rulemakings;

ii. tie any transmission investments to the use of regional planning processes undertaken with the states and interested stakeholders to ensure that whatever transmission is incented is the "right" transmission located at the key location needed to ensure maximum benefit to reliability and economics of grid operation;

iii. encourage and require native load protection but not tolerate discriminatory conduct favoring one's own market position in the name of protecting one's "native load"; and

iv. finally, Congress should make reliability standards mandatory but avoid codifying statutory deference to standard-setting and enforcement in some regions but not others. Deference should be provided to regional solutions, arrived at in open stakeholder processes and with state concurrence, in all parts of the country while any national organization review is limited to ensuring that solutions arrived at on less than an interconnection-wide basis, promote reliability in the larger region. The negotiation of the Joint Operating Agreement and reliability plan between PJM and the Midwest

ISO, which will soon be submitted for NERC review, is an example of the process working at its best with NERC focusing on whether the plan enhances reliability between regions while avoiding the commercial infighting among member companies.

For grid operators themselves, it is clear that we have to ensure that our relay hardware is appropriately sized, maintained and programmed to protect systems in the event of cascading outages. RTOs need to be more vigilant in defining their role vis-à-vis the local transmission owner who still owns and maintains this critical equipment. Agreements such as the MISO/PJM Joint Operating Agreement should be a mandatory "baseline" of coordination between RTOs and should provide appropriate and reciprocal support of adjacent systems both between market areas and where market areas abut non-market areas. And most of all, we need to move this industry forward with flexible policies that are designed to meet and restore the public's confidence in this critical industry so important to our nation's secure future.

I thank you for this opportunity to testify and look forward to your questions.

TESTIMONY OF JAMES P. TORGERSON
PRESIDENT AND CHIEF EXECUTIVE OFFICER
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.
BEFORE THE U.S. SENATE SUBCOMMITTEE ON OVERSIGHT
OF GOVERNMENT MANAGEMENT, THE FEDERAL WORKFORCE
AND THE DISTRICT OF COLUMBIA
SEPTEMBER 10, 2003

Good morning, Mr. Chairman and Members of the Committee. My name is James P. Torgerson. I am the President and Chief Executive Officer of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). I am appearing today to offer what insights I can concerning the circumstances surrounding the power outages and offer suggestions as to what might be done in the future.

The Midwest ISO was formed in 1998. The Midwest ISO is the nation's first voluntary regional transmission organization that did not originate from a legislative mandate or against the back drop of a tight power pool. The Midwest ISO is also the first entity found by the Federal Energy Regulatory Commission to be a Regional Transmission Organization.

The Midwest ISO's region covers portions of fifteen states and the Canadian province of Manitoba. Of relevance to your inquiry here, we act as a Reliability Coordinator for three sets of companies. As Reliability Coordinator, the Midwest ISO monitors, plans, conducts analyses regarding the high voltage grid and communicates with the Control Areas in our region who have the primary control capabilities to open and close transmission circuits and to redispatch generation. We perform this coordination function for the companies that have transferred functional control of their transmission systems to us. We do it through contract with the East Central Area Reliability Council (ECAR) for two systems that are scheduled to transfer control to us in the future, Northern Indiana Public Service Company and First Energy's Northern Ohio system (First Energy's eastern assets are under the control of PJM). Finally, through a contract with MAPPCOR we perform this service to companies in the Mid-Continent Area Power Pool (MAPP) region that have not transferred control of their transmission systems to the Midwest ISO. Three of the more than 30 companies within our reliability coordinator territory suffered outages in the black out – Consumers Power Company, Detroit Edison Company and First Energy Company.

What exactly caused the blackout will be forthcoming from the work being done by the International Task Force formed by President Bush and Prime Minister Chretien of Canada. As Secretary of Energy Abraham's recent press release states: "It's a complex job we are undertaking. … It's going to take some time to compile all this information, get it all synchronized and sequenced, and then determine exactly what happened when – and how it's all interrelated." The Midwest ISO only has a part of the data needed to reconstruct the events and is not in a position to characterize the proximate cause of the blackout. The Midwest ISO is cooperating with the International Task Force and the General Accounting Office's investigations into the matter. Likewise the reason for the cascading effect of the outages is unknown at this time.

The analysis that has been done to date in the Midwest seems to indicate that there were a number of events in the Eastern Interconnection on August 14th. Some are surely related to separations and the substantial losses of load that occurred, and others are likely unrelated.

During the morning and into the afternoon, Midwest ISO personnel were in contact with various control area operators and PJM, the neighboring reliability coordinator about the events of the day, which by the afternoon had included the outages of several high voltage transmission lines. During the morning of August 14th, there was no indication to the Midwest ISO of significant problems in our territory. During the course of the hour preceding the cascading event, after the loss of a large generating unit in northern Ohio had already occurred, several transmission line outages also occurred in the Ohio area. During this period the Midwest ISO operator was in contact with the neighboring Reliability Coordinator at PJM as well as control operators within our territory. At this point in time, the issues did not seem to implicate a regional problem.

Things began to change at 4:09. By 4:10 Eastern Daylight Time portions of the eastern interconnection were separating from one another and the loss of significant load was only seconds or minutes away. At 4:19 the Midwest ISO initiated the first NERC coordinating call of the day among NERC and the regional Reliability Coordinators. These calls were repeated every several hours thereafter and eventually to a few times per day during the restoration. During that first call the issues became ascertainment of system conditions and the commencement of restoration activities.

During the restoration efforts, the Control Area operators performed their responsibilities in linking returning generation with load to be restored. The Midwest ISO, as a Reliability Coordinator, played its part in analyzing the transfer capability into Michigan and Ohio to safely deliver power into those areas. The Midwest ISO worked with each area to ensure the individual area restorations would not threaten even a small-scale repeat of Thursday afternoon's events. The Midwest ISO was able to relay information to Michigan about power available from Illinois that could safely be imported to hasten the restoration of load. Finally, the Midwest ISO, in combination with the IMO and others, determined when it was safe to reestablish the ties between Michigan and Canada. I would also like to add that as part of our normal operations, the Federal Energy Regulatory Commission has stationed two of its professional employees in our headquarters. Among the valuable assistance that they provided, on August 14^{th} these federal employees allowed Midwest ISO to have a single point of interaction with various federal entities concerned with the outage. FERC's dissemination of the real time data from our headquarters allowed Midwest ISO personnel to devote greater attention to system stability and restoration efforts.

As only one of the companies contributing information to NERC and DOE we do not have a picture of events across and adjoining the footprint of affected systems. Events occurring across the eastern interconnection including plant outages, voltage conditions and the operation of protective relay schemes will have to be evaluated before cause can be distinguished from effect. I am awaiting the results of the International Task Force formed by President Bush and Prime Minister Jean Chretien of Canada. However, there are some preliminary observations that I can share with the Committee:

- Equipment that was designed to protect transmission lines and generators during cascading events operated successfully to isolate equipment before there was permanent damage to the equipment. This shortened the time period of the restoration efforts because, had protection systems not operated to protect individual components as designed, the power production and delivery systems could have been severely hampered for many months.
- Automatic protection systems did keep the blackout from spreading even further.
- Considering the size of the area impacted, the restoration proceeded in an orderly manner with much of the load restored within 48 hours of the initial disruption. The Control Areas

have primary responsibility to restore their systems while maintaining a balance of resources and load. The ISO/RTOs assisted in the restoration effort by ensuring equipment was not being put at risk of furthering cascading as generators were being brought back on-line and as load was being restored. The coordination among the ISO/RTOs and their member systems worked to assure a reliable restoration.

I believe a key reason that the Midwest ISO was in a position to help in the restoration efforts was because of our broader regional view of the area. Making a few presumptions, I believe the Midwest ISO will be in a better position next year to lessen the likelihood of any recurrence. We have before FERC a tariff that if accepted and implemented will have the Midwest ISO running wholesale markets, much like PJM, the New York ISO and ISO New England do today. That tariff will put matters like a regional security constrained unit commitment and real time generation dispatch in place. Each of these additions should be of substantial benefit. That will give the Midwest ISO more information about generation unit status than we have today and add an ability to direct generator actions within the footprint. This market will improve reliability. Indeed a strong, reliable system is the necessary underpinning of a successful market. The two are not opposite poles they are two halves of what is necessary for reliable service to customers.

I think all the regional entities involved have an appreciation today that communication between reliability coordinators and other entities has to be raised to a higher level than has been required or practiced in the past. At a basic level, that has already happened. The use of the NERC coordinating call to apprise our industry counterparts of the computer virus on August 20th is an example of that increased communication. Mere telephone communication; however does not seem adequate for the future. The Midwest ISO and PJM have a Joint Operating

Agreement under development that calls for substantial real time automated data transfers between our systems. While the Joint Operating Agreement is not yet finalized, the Midwest ISO and PJM have recently established the physical communication network links to allow for the types of data transfer called for by the Agreement. Once the software is in place the enhanced data transfer can be made operational. We are each reassessing the Agreement to determine what additional features it should have in light of the events of August the 14^{th}.

The Committee is also confronting the question of what can be done to prevent a recurrence of the outages. While the definitive answer cannot be given today, I believe that you will find agreement that widespread adherence to strong enforceable reliability standards will be important. Equally important is state and federal cooperation in transmission siting. I am pleased that the states in the Midwest have formed an organization, the Organization of MISO States, to work cooperatively with the Federal government on, among other things, siting of transmission facilities. We believe such an approach holds great promise to allow the siting of needed transmission facilities while protecting regional efforts to address issues associated with wholesale electricity markets and reliability.

Other matters will be crucial as well. In my opinion they include:

- A reassessment of the existing hierarchical control structure;
- Increased, automated data sharing about system conditions over a wider area; and
- Review of protective relaying practices in the industry.

For the Midwest area as a whole we need the participation of all major transmission systems in an RTO. This will end the prospect of the risks posed by a Swiss cheese configuration of systems, some in an RTO and others not.

Finally, for the Midwest ISO in particular, acceptance by FERC of our tariff filing to establish energy markets in our territory is critical. This will bring added elements of region wide action that are not present today – a security constrained generating unit commitment program and a real-time security constrained economic dispatch.

Of the items I mentioned, the first, mandatory reliability standards is largely in the hands of Congress. As to the development of more infrastructure in our region, the Midwest ISO issued its first transmission expansion plan this June. It calls for construction of $1.3 billion of already planned projects. It identifies another $ .5 billion of proposed reliability projects. Commitment of participating transmission owners to pursue these projects is crucial for the future. The cooperation of the states in allowing timely construction is equally critical.

The remaining items will call for the strong interplay of industry participants and the national government mediated through or directed by the Department of Energy and the Federal Energy Regulatory Commission.

This concludes my remarks and I would be pleased to answer questions.

TESTIMONY OF WILLIAM J. MUSELER

PRESIDENT & CEO
NEW YORK INDEPENDENT SYSTEM OPERATOR

UNITED STATES SENATE
COMMITTEE ON GOVERNMENTAL AFFAIRS
Subcommittee on Oversight of Government Management

September 10, 2003

SUMMARY

The New York Independent System Operator ("NYISO") operates New York's statewide high-voltage electric transmission system. The exact causes of the August 14th cascading blackouts are still unknown and the NYISO will not speculate on them at this time. It is clear, however, that New York and Ontario were directly in the path of massive power flows that took down major portions of the New York system in seconds. The NYISO is cooperating with the International Commission's investigation and expects the Commission to provide the most definitive assessment of what happened. The New York Department of Public Service is also conducting an inquiry with which the NYISO is, of course, cooperating.

The immediate electrical events that caused the blackout in New York occurred at 4:11:00 p.m. Within a few seconds, the New York system was hit by onrushing power flows, reversals and severe frequency and load oscillations. The transmission system was unable to withstand these severe conditions. Approximately 20% of the load, however, continued to receive service during the disturbance. Unfortunately, New York City was completely without power at this point.

Immediately after the event, the NYISO began implementation of its restoration plan. Statewide service was completely restored by 10:30 p.m. Friday, August 15th. The restoration process followed NYISO's pre-arranged plan and worked well. Furthermore, preliminary analysis indicates that New York systems operated as designed. However, it appears that the power swings experienced by New York were beyond what the power system was designed to withstand. The complex protective mechanisms installed on New York's transmission system and power plants worked as intended and no significant damage to the infrastructure resulted.

Even though it is not yet clear what the cause or causes were of the August 14 blackout, it is clear that many actions need to be taken to avoid future problems. These actions include: (i) making mandatory reliability standards and certain operating protocols set by the North American Electric Reliability Council ("NERC"); (ii) making mandatory the incorporation of power systems into ISOs and RTOs; (iii) strengthening the transmission grid in New York state and surrounding areas; and (iv) enhancing the inter-regional planning process.

Testimony of William J. Museler

Good morning, ladies and gentlemen. My name is William J. Museler, and I am the President and Chief Executive Officer of the New York Independent System Operator, or NYISO. I appreciate the opportunity to brief the subcommittee on what we know so far about the August 14, 2003 blackout and our restoration operations. My testimony today will focus on several important federal policy initiatives for improving electric reliability, an agenda that the NYISO and others have been advocating in New York State for several years.

Immediately prior to coming to the NYISO, I was the Executive Vice President of the Transmission/Power Supply Group of the Tennessee Valley Authority, which in terms of MW served, is the size of New York. Prior to that, I was Vice President of Electric Operations at Long Island Lighting Company. I serve as the Chairman of the ISO/RTO Council, and have served on the NERC Board and as Chairman of the Southeast Electric Reliability Council. I am a graduate of Pratt Institute and Worcester Polytechnic Institute.

The NYISO was created to operate New York's bulk transmission system and administer the wholesale electricity markets. We are a New York not-for-profit organization and started operation in 1999. As you know, we are pervasively regulated by the Federal Energy Regulatory Commission ("FERC"). As provided in the Federal Power Act, we are also regulated with respect to certain financings by the New York State Public Service Commission.

I would like to make clear at the outset the areas that we know and those that we do not. While I am, of course, aware of what has been in the press regarding the events that initiated the blackout in a significant part of the Eastern Interconnection, I am not yet able to tell you anything in detail about those events because they have not yet been determined in detail, and details in this case are extremely important. Because the initiating events happened in a very short period of time – really just a matter of seconds – and happened away from New York, understanding them fully depends largely on interpreting electronic data that we do not have. The International Commission formed by President Bush and Prime Minister Jean Chretien of Canada is being given the data[1] and is undertaking its interpretation. We are, of course, cooperating fully in this investigation. The U.S. end of that investigation is well underway and is headed by the Department of Energy. Like you, I'm anxiously awaiting their conclusions. Within New York State the NYISO is cooperating with the Department of Public Service in its own inquiry into the August 14 events.

In addition to outside investigations, the NYISO began its own investigation and analysis within hours of the event. The NYISO is reviewing its own records to determine the precise sequence of events that took down major portions of the New York system within fractions of a second. We have, in our preliminary analysis, identified two uncontrollable power swings that led to the New York system disturbance that occurred at about 4:11:00 p.m.

Up until the event, our system was operating normally, well within applicable criteria and with adequate reserves. The immediate electrical events that caused the blackout in New York occurred at 4:11:00 p.m. Within a few seconds, our system was hit by onrushing power flows, reversals, and severe frequency and load oscillations. The transmission system was unable to withstand these severe conditions. However, several hydro plants in upstate New York, as well as the Quebec tie line, remained in service, as did the majority of the upstate transmission system. Thus, about 20% of the New York load continued to receive service during the disturbance. Unfortunately, New York City was left completely without service at this point.

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[1] NERC has been designated as the central data collection and analysis point and all data is being sent to them.

Immediately after the event, the NYISO began implementing its restoration plan. The first step in the restoration process involves stabilizing the system and restoring our ties to the neighboring control areas. After that, the process of bringing power plants and outside sources back online must take place, including the delicate balancing of the power they can supply with the demand in the individual area being restored. If the demand were greater than the supply, the system would crash in the affected area, and fortunately that did not occur.

Within about three hours, we were able to restore one major tie to the remainder of the Eastern Interconnection at Ramapo. The first major power plant was returned to service in just under an hour after that, and a few minutes later we re-established a transmission path to New York City. Throughout the next day, there was a painstaking process of bringing generators back to the system and re-energizing lines. Statewide service was completely restored by 10:30 p.m. Friday, August 15th. The restoration process followed NYISO's pre-arranged plan and it worked well.

Preliminary analyses indicate that the New York system operated as designed, given the event, and that the power swings New York experienced were beyond anything the system had been designed to withstand. In an occurrence such as the recent blackout, the greatest danger to electric service is potential damage to the system itself—the power plants and the transmission lines. Had that kind of damage occurred, it could have taken days, weeks, or even months to restore. Fortunately, the complex protective mechanisms that had been installed on New York's transmission system and on its power plants worked as intended and no serious damage was done. This protection shortened the restoration process considerably.

The Subcommittee has requested our view of "the next steps…to ensure that we do not have another incident of this nature." As I stated earlier, however, the events that so affected

New York and other states on August 14th are not yet known in sufficient detail to plan and implement specific solutions. Nevertheless, we believe it makes sense to examine the known problems that could give rise to other reliability concerns in the future. I will go over for you several important policy initiatives for improving electric reliability in which we believe the federal government should take a leading role.

Mandatory Reliability Standards. We believe that the reliability standards set by the NERC, which are now voluntary, should be made mandatory. That issue is now before the Congress in the energy legislation now before a conference committee.

Communications. We also believe that the standards should mandate significantly improved communications and operating protocols among the various regions of the country, since we are now painfully aware of the extent to which events in one region can affect neighboring regions. Right now, there is no expectation that a non-adjacent system operator would communicate to other, non-contiguous control areas the existence of a condition or disturbance on its system or other systems that could jeopardize other regions. While there is no guarantee that such improved communications would make possible anticipatory actions that would prevent the spread of a problem, it is obvious that advance warning would give operators more time to try to take protective actions.

ISOs and RTOs. We also believe that the incorporation of power systems into ISOs and RTOs should be mandatory. The main difference between an ISO and an RTO is its geographic scope. An RTO generally covers a larger geographic area than an ISO. Interestingly, the four most populous states in the Country have all chosen to operate as single state ISOs or RTOs. FERC Order No. 888, which provides the framework for open access to the interstate transmission system to facilitate wholesale competition, encouraged but did not require transmission-owing utilities to create ISOs. The decision to create an ISO or other type of entity with similar functions, such as an RTO, is currently voluntary and rests with state utility commissions.

ISOs and RTOs generally act as the primary interface between generators, transmission owners and other participants in the wholesale electric marketplace. ISOs and RTOs accomplish this by dispatching the power system in their control area (i.e., directing the power plants to generate a specific amount of power at a specific time) to supply electricity to customers while maintaining safety and reliability. (In addition, ISOs and RTOs generally facilitate and administer a number of different electricity markets, thereby providing market participants with the ability to sell and purchase various services on an unbundled basis.) Given the extensive and growing commerce that takes place in electricity, it is clear that reliability requires coordination and operation at a level above that of the local electric company. In today's environment this can best be done by an ISO or RTO.

Adequate Electric Generation. In addition to the previously stated policy initiatives, there are some actions that can be taken to help ensure that other reliability problems do not arise. New York has been short of generation in the recent past and projections indicate that deficiencies are likely again later this decade. That shortage will grow and will represent both a reliability concern and, in our new competitive markets, a cost to consumers. The financing and siting of new power plants are issues that must be dealt with through the markets for electricity and reasonable siting laws. The NYISO has already reformed its capacity markets to encourage investment in needed facilities and is working with neighboring regions to develop regional capacity markets.

<u>Strengthening the Transmission Grid</u>. Adequacy of the transmission grid affects both reliability and the cost to consumers. Inadequate transmission hampers free trade and competition, resulting in unnecessary cost to consumers. It also enables systems better to withstand potentially disruptive events. New York's transmission grid and its internal planning process needs to be strengthened. Current incentives for building transmission are inadequate. Likewise, both intra and inter-regional planning processes should be improved, and in the case of interstate facilities, a federal override (backstop federal siting authority) may be appropriate.

In this brief statement, I have tried to summarize the state of the investigations into what we know about how we handled the recent blackout in New York. I have tried to do so without speculating on things about which it is premature to draw conclusions. Needless to say, once the results of the international investigation are available, the NYISO will move aggressively to implement appropriate changes, as indicated by that investigation. Finally, I have taken the opportunity to alert the subcommittee to some of the measures, which can help to avoid future problems.

I want to thank you for the opportunity to come here today, and assure you that we will be cooperating with the on-going inquiries into the outage.

BEFORE

THE UNITED STATES SENATE

SUBCOMMITTEE ON OVERSIGHT OF GOVERNMENT MANAGEMENT,
THE FEDERAL WORKFORCE AND THE DISTRICT OF COLUMBIA

TESTIMONY OF JAMES Y. KERR, II

NORTH CAROLINA UTILITIES COMMISSION

The 2003 Blackouts: The Federal Role and Response

September 10, 2003

Mr. Chairman, my name is Jim Kerr. I am a member of the North Carolina Utilities Commission (NCUC), having served on that body for a little more than two years. I am also a member of the Electricity Committee of the National Association of Regulatory Utility Commissioners (NARUC), the Immediate Past President of the Southeastern Association of Regulatory Utility Commissioners (SEARUC) and currently serve, along with Marilyn Showalter, Chair of the Washington Utilities and Transportation Commission, as the Co-Chair of the Alliance of State Leaders Protecting Electricity Consumers (Alliance).

Please note that in submitting this testimony, I am speaking for myself, not the NCUC, NARUC, the Alliance, or SEARUC. Although my comments are informed by my discussions and exchanges with fellow regulators and industry stakeholders, these are my views, not those of the aforementioned organizations or their members.

I very much appreciate the opportunity to appear before the Senate Subcommittee on Oversight of Government Management, the Federal Workforce and the District of Columbia and to assist in your consideration of the cause of the August 2003 Northeast blackouts and the appropriate response of the federal government to ensure that similar events are not a part of our nation's future. Specifically, I have been asked to discuss the causes of the blackouts, as well as the current federal role in managing and regulating the generation and the transmission of electricity. The discreet issues that you are addressing today are of great national importance; they also are relevant to broader, equally important, subjects facing this Congress in the context of pending federal energy legislation.

As you consider these matters, I encourage you to carefully consider the impact of any proposed electricity legislation on each region of the country, including the Southeast, because of the significantly different manner in which electric service is provided to retail customers in each part of the country. Thus far in its consideration of the recent blackout, Congress has heard only from federal officials or from representatives of the regions of the country that were affected directly by the blackouts. I hope to provide you with a broader perspective from which to consider both the recent events and the appropriate federal responses. To this end, I would like to describe for you the structure of the electric system in North Carolina and the Southeast, our approach to reliability, and my thoughts on appropriate federal responses to the recent blackouts.

At the outset I want to make clear that my purpose is not to tout the electric system in North Carolina (or the Southeast) as perfect or the only acceptable system design. Nor do I advocate congressional action that would prevent a region of the country from pursuing the electric market structure that best suits that region's needs. My message is that Congress must be careful that, in responding to recent events, it does not pursue perceived solutions that will adversely affect electric systems that are, in fact, working well.

OVERVIEW OF THE ELECTRIC SYSTEM IN THE SOUTHEAST

Regulatory Jurisdiction

The NCUC, like other similar bodies across the country, is an agency of state government responsible for regulating the rates charged and terms and conditions of retail electric service provided by the entities defined by our General Assembly as "public utilities." Under North Carolina law, our electric jurisdiction extends to "persons" owning and operating equipment and facilities for the production, generation, transmission, distribution, and furnishing of electricity. Our statutory authority, where it applies, is broad and plenary, encompassing all aspects of the retail service provided by the utilities under our jurisdiction.[1]

[1] The NCUC's jurisdiction does not, however, extend to rural electric cooperatives and municipal distribution systems, subject to certain limited exceptions.

While the NCUC's jurisdiction is focused on the provision of retail electric service, the Federal Energy Regulatory Commission (FERC) also plays a role. In 1935, in response to the United States Supreme Court's Attleboro[2] decision, Congress enacted Title II of the Federal Power Act, which created FERC (then the Federal Power Commission). Congress' intent was to establish a body that could regulate certain interstate activities of utilities that the Court in Attleboro suggested were beyond the reach of state regulators. Accordingly, FERC was given authority over wholesale power sales and the transmission of electricity in interstate commerce.[3] This combination of the states' plenary authority over retail electric service and FERC's interstitial jurisdiction over specific matters that might evade state regulation has been the cornerstone of the regulatory framework in the Southeast for almost 80 years.

The Provision of Electric Service in the Southeast

Electric service in the Southeast continues to be provided, in large part, by vertically-integrated utilities subject to the regulatory oversight of state commissions. These utilities own and operate generation, transmission and distribution facilities, which they use to serve their customers, including hospitals, schools, churches, and homes. Although I have not made a comprehensive study of the laws in other Southeastern states, North Carolina law clearly contemplates the continued existence of such vertical integration. The only common exceptions to this model in most of the Southeast are rural cooperatives or municipal electric systems, some of which own electric distribution systems, but not generation or transmission facilities.

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[2] Public Utilities Commission v. Attleboro Steam & Co., 273 US 83, 71 L Ed 549, 47 S Ct. 294 (1927).

[3] 16 USC §824, et seq. (2003).

The Role of the Wholesale Power Market in the Southeast

The continued existence of the traditional industry structure throughout most of the Southeast does not mean that we are indifferent to the potential benefits of a properly-functioning wholesale market. On the contrary, the NCUC recognizes that a properly-functioning wholesale market can benefit the retail customers of our vertically-integrated utilities in a number of ways. First, the wholesale market can provide enhanced opportunities for our utilities to procure competitive generation from independent power producers as an alternative to utility-built options. Secondly, the wholesale market can provide opportunities for additional short-term economy purchases, allowing our utilities to reduce their costs by purchasing power instead of operating more expensive units on their own systems. Finally, the wholesale market can allow vertically-integrated utilities to share reserves, effectively reducing the costs of maintaining system reliability. As a result, I do not believe that any of my colleagues disputes the benefits of a properly-functioning wholesale market to retail customers despite the continued presence of traditional, vertically-integrated utilities.

The NCUC, and the utilities we regulate, have taken steps to take advantage of the potential benefits of the wholesale market in recent years. When the utilities procure additional capacity to meet anticipated future load, they typically issue a request for proposals to solicit wholesale power offers that are compared with the cost of self-build options prior to making a final resource procurement decision. Also, the records in our fuel adjustment cases demonstrate that our jurisdictional utilities purchase substantial amounts of power from marketers and brokers in lieu of generating power from their own facilities when it is economic to do so. The NCUC adopted procedures to facilitate the recovery of the costs associated with such purchases in order to encourage our utilities to make the best economic decisions for retail customers and we have revised our generating plant certification rules to make it easier to site and construct merchant generating facilities in our state. To date, we have not rejected any application for the issuance of a merchant plant certificate. Thus, North Carolina Utilities Commission has embraced the opportunities for cost savings and reliability improvements available on the wholesale market and I feel confident that the rest of the states in the Southeast have taken steps to do the same.

However, the potential benefits of wholesale market improvements for the retail markets in North Carolina and most other Southeastern states are not unlimited. The ultimate purpose of the wholesale electric market is the same as most wholesale markets—supporting the retail market. As noted above, the vast majority of the power sold at retail in the Southeast is generated by utility-owned facilities. Although certain municipal and cooperative electric systems rely more heavily on the wholesale market, the simple fact of the matter is that, for the foreseeable future, the impact of wholesale market improvements in the Southeast is likely to be relatively limited. While the importance of the wholesale market in the Southeast may increase over time, the potential benefits of an improved regional wholesale market in the near term should not be oversold. As a result, any attempt to redesign wholesale electric markets should include a careful weighing of the costs and benefits for the retail markets, including the costs of implementation.

Conclusion

With the exception of Virginia, retail competition is not authorized anywhere in the Southeast, and it appears that our neighbors in Virginia are reconsidering their movement toward retail competition. Arkansas recently repealed the retail competition statute that it enacted a number of years ago. It is my impression from talking with colleagues throughout the region that none of the other Southeastern states are likely to move to retail competition in the near future.

At this point, the general perception among Southeastern regulators is that the regional system for providing electric service is, on balance, working well. Our rates are among the lowest in the country. We have not experienced any significant reliability problems in recent years. Our reserve margins generally are adequate. A study of the regional transmission infrastructure performed by SEARUC found no material transmission bottlenecks.[4] While our electric system is not perfect, the available evidence has not led our state legislatures to support radical restructuring of the type adopted in certain other parts of the country. Unquestionably, the decision of whether, when, or how to restructure retail markets is a decision for each state to make instead of a matter to be decided at the federal level. As a result, the existing industry structure in the Southeast is likely to remain in place for the foreseeable future.

THE SOUTHEAST'S APPROACH TO RELIABILITY

The states and electric utilities in the Southeast were not directly affected by the August 14, 2003, blackouts. Therefore, we do not have any firsthand knowledge of the specific causes or contributing events which led to the blackouts. Nevertheless, even with limited and imperfect knowledge at this time, we have an obligation to try to assess this series of events and learn from them. Thorough reviews are underway by the affected states, Congress, United States Department of Energy, the North American Electric Reliability Council (NERC), and others that should shed more light on this event. Utilities and state commissions in the Southeast are closely analyzing and studying the results of these and other investigations to determine what

[4] See Letter from James Y. Kerr II to Chairman Pat Wood, Federal Energy Regulatory Commission, dated August 22, 2002, attached hereto as Exhibit A.

"lessons can be learned" and whether new measures should be adopted in our jurisdictions to further reduce the possibility of similar events affecting our region in the future. I would add that both North Carolina and South Carolina utility regulators have already met with the Southeastern Electric Reliability Council (SERC), PJM, and the utilities that we regulate in order to begin this process.[5]

Although we do not yet have clear answers, we as regulators must be able to answer the questions of what happened on August 14th and how we prevent a reoccurrence. Indeed, those questions are the reason we are all gathered in this room today. While the exact causes of the blackouts are still unknown, numerous industry experts have narrowed their focus to at least three general factors as potential causes:

1. *Accountability for Reliability;*
2. *Transmission Planning and Investment; and,*
3. *Operational Coordination and Communication.*

I would like to take the next few moments to describe how the Southeast and, in particular, my state of North Carolina addresses each of these factors.

Accountability for Reliability

– In the aftermath of the blackouts, all of our utilities were asked whether similar problems could occur in the Southeast. For the utilities that are in unrestructured systems, the answer was easy. We know who has the statutory responsibility for both generation and transmission adequacy. Accidents can happen, but there is political and regulatory accountability in the utilities and in their regulators. In restructured systems, it is harder to find both the technical and political accountability. A large fraction of the grid is used for strictly commercial transactions, rather than bundled sales to native load. Utilities, and by extension their state and local

[5] See Exhibit D for the presentation made by North Carolina utilities to the NCUC.

regulators, have a smaller role in the building of both new generation and new transmission which makes accountability divided and unclear.

Accountability and responsibility are clear for North Carolina and much of the Southeast. North Carolina law requires public utilities to provide reliable and adequate electric service to all customers in their assigned territories at reasonable rates. Annually, these utilities provide reports and resource plans to the NCUC in order to demonstrate the steps they are taking to fulfill those obligations in the near term and in the long term. These reports and plans are subject to public scrutiny by customers and regulators. Each exhibit is exposed to public debate and the results are resource plans that are responsive to the needs of customers while meeting the utilities' statutory obligations. Further, utilities in North Carolina are subject to answering for service deficiencies in the form of formal and informal customer complaints lodged with the NCUC. Even on its own motion, our Commission can inquire into any aspect of the utilities' operations and take steps to require improvements to transmission, distribution and generation service or take definitive rate-making action if circumstances so require. In short, there is never any question what party has responsibility for reliability in resources and planning. Nor is there any doubt about the process by which those goals are achieved.

Transmission Planning and Investment

The planning process in the Southeast is a bottom up approach that has been in place for many years. Each utility in North Carolina and many other utilities in the Southeast are mandated to engage in integrated resource planning, which involves the joint planning of generation, transmission and demand management. The utilities are then required to file these integrated resource plans with the state commissions in order to assure them that reliability will be maintained. The process begins with long term (typically 10 year) plans developed by the individual utility using NERC, SERC and system reliability criteria. These plans are then combined at the sub-regional level (for North Carolina it is called VACAR – Virginia, North Carolina and South Carolina) and are tested using computer models against NERC reliability criteria and for the ability to transfer power between systems. The plans from each sub-region are further combined to develop a SERC regional plan (which encompasses VACAR, Southern, Entergy and TVA). Again, the plans are tested using computer models for compliance with NERC and SERC reliability criteria. Finally the plans are combined at the multi-regional level where they again are tested for reliability compliance. This process has worked very well and continues to keep the lights on in the Southeast.[6]

The overall success of the integrated and regional planing processes in the Southeast stands in sharp contrast to the claims of some who say that America has a "third world transmission grid." I would agree with my colleague Dr. Schriber of the Ohio Public Utilities Commission that these statements are simply untrue, at least for the Southeast. I do not doubt that some areas of the country need more transmission construction. The Southeast, however, is not lacking in transmission investment. In 2002, the utilities in the Southeast invested over $1 Billion in the transmission grid and over the next five years the utilities plan to invest more than $6 Billion in the Southeast transmission grid.

More importantly, the Southeast transmission grid is operating well for the specific purpose for which it was designed – to serve local load with adequate reserves for reliability and wholesale transactions. We have not experienced the blackouts, market meltdowns, price spikes,

[6] For a more detailed description of the SERC planning process, see Letter to Representative Tauzin from SERC Executive Director William Reinke, dated August 28, 2003, and the SERC presentation to the North Carolina Utilities Commission, dated August 26, 2003, attached hereto as Exhibits B and C respectively.

and various problems that have plagued other regions. Even more minor transmission problems, which are referred to by the industry as Transmission Loading Relief measures (TLR), have not cropped up as often in the Southeast as they have elsewhere. For example, throughout North and South Carolina, only 3 TLRs were called in 2002. Whereas, PJM called 95 TLRs and the Midwest ISO called 950 TLRs in 2002.[7] Can the system planning processes used in the Southeast be improved? Certainly, there is always room for improvement. However, the planning, construction and operation of the transmission grid in the Southeast has served the region well to date.

Operational Coordination and Communication

The now well-publicized transcripts of conversations between RTO and utility personnel leading up to the blackouts suggests that lack of clear, prompt communication may have contributed to the problems. On this point, it is worth reiterating that whatever theoretical value there might be in disaggregating utility operations, there is always going to be the practical concern that too much disaggregation is going to require lightning fast communication AND reaction by multiple parties, each with their own limited perspectives and interests. Can this be accomplished seamlessly? Perhaps. But what we know for sure is that the structure of vertical integration, coupled with regional coordination, allows utilities in the Southeast to respond to unforeseen events quickly and efficiently. The ability of utilities that operate transmission and generation facilities to coordinate and adjust those operations instantaneously in real time unquestionably enhances their ability to react to emergencies such as the events of August 14th.

[7] See www.nerc.com/pub/sys/all_updl/oc/scs/logs/trends.htm for a more detailed description of TLRs throughout the nation.

In my opinion this approach is responsible for the consistent reliability the Southeast enjoys in normal and extraordinary conditions.

APPROPRIATE FEDERAL RESPONSE

In your consideration of the appropriate federal response to the events of August 14th, I would encourage you to first consider a few very basic principles. First, acknowledge the one lesson from the events of August 14th that is beyond question - - the provision of reliable electricity to the nation is of vital importance to the lives of its citizens and to its economy and security. Second, until more is known about the actual cause or causes of the blackouts, you should be very careful about either jumping to conclusions or using those events as the basis for any legislative action. Finally, any potential solution you might consider must "do no harm" to the existing industry structure as it might exist throughout the country. With these basic principles in mind, I would like to comment first on some of the broader policy initiatives that some proponents have raised as possible solutions to the issue of reliability and then on several of the more discreet proposals that more directly impact on reliability.

Regional Transmission Organizations and Standard Market Design

Some proponents of the FERC's restructuring efforts are pushing mandatory Regional Transmission Organizations ("RTOs") and Standard Market Design (SMD) as the cures for the yet-to-be-determined causes of the blackouts. I do not believe that such expansive overhauls are necessarily relevant and they are certainly not the answer. As noted above, the blackouts occurred in areas that have gone the farthest in implementing RTOs and SMD. The formation of

RTOs and the adoption of SMD do not add a single transmission line or a single kilowatt of new generation capacity, but will cost many millions of dollars to implement. RTOs and SMD may be helpful in some regions, and any area that desires to pursue such restructuring efforts should be allowed to do so. By the same token, RTOs and SMD do not appear to be necessary or beneficial for every part of the country. In that regard, I think it is safe to say that most of my fellow regulators in the Southeast have considerable doubts about the appropriateness of those policies for our region. Southeastern regulators have been considering these issues generally and in the context of the specific RTOs that have been proposed in the Southeast (i.e., SeTrans, GridSouth and GridFlorida). Also, SEARUC recently commissioned a cost-benefit analysis to determine if the benefits of RTOs and SMD outweighed the costs.[8] The results of that study raise serious questions as to whether the benefits of forming an RTO and implementing SMD in this region would exceed the costs and risks. A more recent cost-benefit analysis performed by the Department of Energy raises similar questions about whether the implementation of RTOs and SMD would increase costs to retail customers in the Southeast.[9] Moreover, even though DOE's study suggests that there may be net savings from the implementation of SMD under optimal conditions; those savings are extremely modest – less than 1% on a nationwide basis – and take years to materialize. This strikes me as a very thin potential return for such a high-risk investment.

[8] See http://www.state.va.us/scc/searuc/cra_study.pdf for a copy of the Benefits and Cost of Regional Transmission Organizations and Standard Market Design in the Southeast dated November 6, 2002.

[9] See www.energy.gov for a copy of the Department of Energy Standard Market Design Cost/ Benefit Report dated April 30, 2003.

Furthermore, I am concerned that RTOs and SMD could have the unintended effect of harming reliability. FERC's policy initiatives appear to be moving towards disaggregation (the separation of generation and transmission functions) and this raises the question as to whether such separation has an effect on reliability. Among other things, these FERC initiatives encourage long distance transfers of power. Because the ability to serve load becomes more susceptible to problems caused by the loss of critical transmission lines, these long distance transfers raise reliability concerns. In contrast, when generation is located near load, there is less distance for the power to travel before it reaches the load and hence less opportunity for problems.

I am also concerned that the FERC's restructuring model usurps state jurisdiction over electric service, which would seriously impede the state commissions' ability to exercise their statutory responsibility and to assure that retail customers in their states are served reliably and in a cost effective manner. This set of circumstances leaves state regulators with little authority vis-à-vis the RTO to address day-to-day issues much less to deal with extraordinary events such as the recent blackouts. While the FERC has indicated that state commissions might be able to play an advisory role in the new world of SMD and RTOs, this is a poor substitute for jurisdiction and direct accountability and gives Southeastern states serious concern.

Reliability Standards

A consensus is building within the electric industry to support federal legislation to establish mandatory, enforceable reliability standards through an industry-led, self-regulating organization (*i.e.*, NERC). I support that effort; in particular I support the current electric reliability language in the House Energy Bill (HR 6, Section 216). NERC has developed an appropriate set of planning and operating standards and those standards will most likely be further improved following the evaluation of the August 14th blackouts. While voluntary compliance with these standards has worked well in the Southeast, it is possible that some regions may need mandatory reliability rules to provide additional assurance of reliability.

As part of the effort to establish mandatory reliability standards, some have proposed that the FERC be authorized to review and enforce NERC's reliability standards. While I recognize that some governmental authority probably needs to have oversight responsibility, I am concerned about such a proposal for two reasons. First, the FERC has no reliability expertise that I am aware of; thus, FERC would need to rely upon industry experts such as NERC who have traditionally been the ones in charge of reliability criteria. Second, the FERC must not be allowed to use any newfound reliability authority as a way to promote its regulatory agenda to restructure the wholesale market. For this reason, any federal legislation would need to be carefully structured to ensure that the FERC's additional authority is limited to the promotion of reliability. Legislation must not allow FERC to use reliability authority to pursue the mandatory restructuring of markets across the nation. In particular, the FERC must not be allowed to use any such reliability legislation to try to force mandatory RTO participation or the adoption of SMD.

Transmission Incentives

To encourage transmission construction, some entities are recommending the adoption of incentive rates. In certain circumstances, incentive rates might be appropriate. For example, the adoption of accelerated depreciation for transmission construction would appear to be an appropriate catalyst to spur new investment. However, I do not believe as a general matter that incentive rates are always necessary, at least not in the Southeast. As previously discussed, the utilities in the Southeast, with oversight from their state regulators, have done and continue to do an admirable job of ensuring that sufficient transmission investment is made to provide economical and reliable electric service to consumers. Importantly, this investment is being made under the traditional regulatory model of relying upon vertically-integrated utilities that receive a regulated return on their investment. Incentive rates should be directed at transmission projects that would not be constructed under the traditional model; otherwise such incentives will serve only to raise rates for consumers.

Another transmission-related incentive being discussed involves the tax treatment of transfers of transmission assets. Generally speaking, this provision would limit the tax exposure of utilities that transfer transmission assets to other entities. This provision may be desirable to remove an obstacle for utilities that are interested in transferring their transmission assets; it must be emphasized, however, that in many, if not most, states in the Southeast, any such transfer would require the approval of the state regulatory commission.

Backstop Siting Authority

Another proposal being discussed in response to the blackouts is to provide the FERC siting authority to allow it to authorize the construction of new transmission investment. This proposal raises serious concerns. As an initial matter, sufficient transmission lines have been and are being constructed to maintain reliable service to consumers in the Southeast. While some claim that problems arise when utilities try to build interstate transmission lines, it bears noting that many utilities in the Southeast are multi-state in nature and already work with different jurisdictions in planning and siting transmission facilities. In short, the siting of transmission lines, like most land use issues, raises many local concerns. If a transmission line is not authorized by the state, there would likely be very good reasons for that decision – reasons that should not be easily discounted. For these reasons, any legislation to give the FERC "backstop" authority to site transmission must acknowledge the states' primary role in the siting of transmission and carefully prescribe the FERC's authority to overrule those decisions. This is especially true given the various efforts that are already underway to encourage greater coordination and cooperation among ~~the~~ states on planning and siting issues.

The above mentioned statements on federal siting authority are my own opinions but, as a member of NARUC, I feel obligated to state that NARUC respectfully opposes any provisions that contemplate federal siting authority for transmission (direct or backstop). NARUC believes that states should retain authority to site electric facilities. Congress should support the states' authority to negotiate and enter into cooperative agreements or compacts with federal agencies and other states to facilitate the siting and construction of electric transmission facilities as well as to consider alternative solutions to such facilities, such as distributed generation and energy efficiency.

CONCLUSION

The actual cause or causes of the August 14th blackouts are as of yet unknown. What is certain is that this event provided all of us with a dramatic and unfortunate reminder of the vital importance of reliable electricity to all of our lives. As this Congress begins to understand better the actual causes of the blackouts and the appropriate responses it might take, I encourage you to keep the unpleasant memories of that day in the forefront of your minds as a reminder of how much we all risk in formulating our responses. Much is being done correctly and appropriately in all of the regions of the country and you should first "do no harm" to that which is working effectively in the various regions. Only then should you undertake responses that will build upon that which is working in order to enhance the reliability of electric service to the entire nation.

The Southeast's model for utility service is not the only such model that can work, and my testimony here today should not be interpreted as indicating otherwise. However, there can be no serious debate that the electric system in our region works and works well. It is a system that our citizens have invested in for decades and it has delivered on its purpose - - producing highly reliable, reasonably priced power that meets the expectations and needs of our citizens. While not perfect, the system of regulation upon which our electric system is based is in large part responsible for this result. With that said, I understand that other regions of the country have problems that they are trying to solve and I support the Southeast helping in any way that we can, as long as that support is not a detriment to the reliable and efficient electric system we have built for the Southeast. We continue to believe that the balance of risks and tradeoffs associate with changing this system are best assessed by the policymakers closest to, and politically accountable for, the actual operations of the system. Accordingly, in order to ensure the continued provision of reliable service in our region, this Congress and federal regulators must avoid the precipitous implementation of policies which will disrupt the smooth functioning of our current system. By the same token, Congress and federal regulators can and should implement policies that are narrowly drawn, cost effective, reflective of the regional differences that exist, and which can improve upon the reliability and operation our electric system and that of other regions.

Thank you for the opportunity to be with you today and to provide my perspective on these important issues.

EXHIBIT A

SOUTHEASTERN
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◆ KENTUCKY
PUBLIC SERVICE COMMISSION

◆ KENTUCKY
RAILROAD COMMISSION

◆ LOUISIANA
PUBLIC SERVICE COMMISSION

◆ MISSISSIPPI
PUBLIC SERVICE COMMISSION

◆ NORTH CAROLINA
UTILITIES COMMISSION

◆ SOUTH CAROLINA
PUBLIC SERVICE COMMISSION

◆ TENNESSEE
REGULATORY AUTHORITY

◆ VIRGINIA
STATE CORPORATION
COMMISSION

August 22, 2002

VIA FACSIMILE AND U. S. MAIL

The Honorable Pat Wood, III, Chairman
Federal Energy Regulatory Commission
888 First Street, N. E.
Washington, D.C. 20426

Re: Testimony Before the United States Senat Committee on Energy and Natural Resources, Ju 24, 2002

Dear ~~Chairman Wood~~ Pat:

On behalf of the Southeastern Association of Regulatoı Utility Commissioners (SEARUC), I would like to take th opportunity to respond to the transmission infrastructure testimor which you presented to the United States Senate Committee c Energy and Natural Resources on July 24, 2002. There are sever items within your testimony that do not reflect the current situatic in the southeastern states, and for that reason we feel compelled t correct the record for the benefit of our elected representative Specifically, we are responding to the following four assertions your testimony:

- *The grid in the southeast ... is inadequate to serve th needs of the competitive wholesale market.*
- *[I]ncumbent transmission companies have tended to act ways that favor their own generation and impede pow flows for independent generators.*
- *The central question to be resolved in the southeast is, wh should pay for the new transmission facilities that a desperately needed for the region as a whole?*

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- *Although the residents of Mississippi, Alabama and Louisiana are benefiting from the investment dollars, jobs and tax benefits of [merchant] power plants, they are reluctant to pay for any new transmission lines that may be needed to enable these plants to reach their intended interstate markets.*

(Testimony at 7.)

First and foremost, we would note that there are not now, nor are there projected to be, any transmission infrastructure deficiencies in the southeastern region of the United States. In fact, during the Federal Energy Regulatory Commission (FERC) infrastructure conference in Orlando, Florida, over which you presided during May of this year, we presented you with SEARUC's in-depth analysis of the transmission situation in the southeast, the Southeastern Infrastructure Assessment (SIA Report)[1], based on up-to-date data as reported by the North American Electric Reliability Council (NERC) and the Southeastern Electric Reliability Council (SERC). Transcript of the Southeast Infrastructure Conference, at 169 (FERC Docket No. AD02-13-000, May 9, 2002) (Tr.). This analysis indicates that the southeast has sufficient transmission capacity for the present and foreseeable future as well as a significant projected excess of generation capacity. (SIA Report at 1.) Upon receiving this information in May, you and your fellow commissioners expressed great satisfaction with the current state of affairs in transmission infrastructure in the southeast, particularly when compared with that of other regions of the country.[2]

Secondly, contrary to the statement in your Senate testimony, we are not aware of any actions by the regulated incumbent transmission companies in the southeast to "impede power flows" or otherwise discriminate against independent generators. In fact, the only testimony contradicting the adequacy of the southeastern transmission infrastructure that was presented during the infrastructure conference in Orlando was made by a member of your staff, Mr. Scott Miller. His testimony, however, was based only on "anecdotal" evidence rather than actual data, as was noted for the record with concern by Commissioner Brownell. (Tr. at 19.) In addition, your recently issued notice of proposed rulemaking on standard market design (SMD NOPR, Docket No. RM01-12) offers scant evidence of discriminatory conduct by any utility in the southeast, hardly sufficient to justify the proposed assumption of federal jurisdiction over bundled retail service in the region. We have previously offered our assistance in dealing with any

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[1] In addition to providing the SEARUC Southeastern Infrastructure Assessment to you and your staff in person in Orlando, it is available on the Internet at <www.psc.state.fl.us/general/publications/searuc.pdf>.

[2] MR. CALLAHAN: Well, do you feel good about what you've heard?
MR. WOOD: I do.
MR. CALLAHAN: Do you feel good about the infrastructure in the southeast?
MR. WOOD: For me, yeah. Linda's nodding. Nora? I saw some of the issues and I haven't had time to digest them about the, in the transmission study yesterday that was released by the Department of Energy that I'd like to, and I think probably will mention a little bit in the [SEARUC] study. And since I just got both of those today, I'd like to say a qualified yes. But I like what I heard. I think it's, kind of makes it easy to move onto the next one [infrastructure conference], which won't probably be as easy. (Tr. at 200.)

such anti-competitive behavior and ask, again, that you provide us with any facts or complaints supporting such allegations.

Thirdly, after having received our report in Orlando on the adequacy of the transmission infrastructure in the southeast and having expressed satisfaction with what you heard, you reported to Congress that "new transmission facilities ... are desperately needed for the region." However, several corporate officers of the major transmission-owning electric utilities in the southeastern states testified in Orlando that transmission infrastructure has been and is being built as needed to meet the needs of consumers in the southeast. Mr. Bill Newman, Senior Vice President for Transmission and Planning in Operations at Southern Company Services, testified that traditional planning has worked and is working well in the southeast to ensure that transmission is planned and expanded appropriately. He also testified that these transmission systems were designed and built so there is no congestion even with a transmission line or generating plant out of service. With respect to new infrastructure, Southern has budgeted to invest $3 billion in transmission over the next five years to serve its native load and its current network and point-to-point wholesale customers. (Tr. at 76-77.) In summary, our regulated electric utilities have invested, and are continuing to invest, in transmission infrastructure as needed for customers in the southeast, and the region does not "desperately" need new transmission facilities as stated in your testimony.

We agree, however, that one vitally important issue is that of who will pay for the transmission expansions and upgrades that will be necessary to move to market the tremendous amount of merchant plant capacity that has been proposed to be built in the southeast. While some of this excess capacity can be sold in the southeast, it will not be economic for those plants to supply power solely in the southeast and stay in business. Because the developers of these merchant plants chose to locate in the southeast while planning to sell to other parts of the country, a tremendous amount of new transmission infrastructure will have to be added and dedicated to that purpose. It has been and remains our contention that, if our ratepayers will not benefit from the excess generation capacity that moves to distant markets, they should not be burdened with the billions of dollars in new transmission costs needed to export that capacity. We are pleased that the FERC agreed in the SMD NOPR to consider participant funding, and would encourage you to apply such a pricing policy to fund the transmission requirements of such plants.[3]

[3] Participant funding has been endorsed previously by SEARUC and by the National Association of Regulatory Utility Commissioners:

> [N]ow therefore be it
>
> RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened in its February 2002 Winter Meetings in Washington, D.C., hereby urges the Federal Energy Regulatory Commission (FERC) to utilize a pricing policy which provides that the cost of investments, that have been demonstrated, through an even-handed assessment of transmission, generation and

The Honorable Pat Wood, III
August 22, 2002
Page 4

Lastly, we would inform you that states such as Mississippi, Alabama and Louisiana have not, contrary to the assumptions set forth in your testimony, received either employment or tax revenue benefits commensurate with the billions of dollars that will be required for new transmission infrastructure to transmit to other regions of the country the excess merchant power described above. These merchant plants, meanwhile, are consuming the natural gas and water resources of those states and are imposing other costs that must be balanced against any benefits. In short, there is certainly no level of benefit to those states that could come close to offsetting the tremendous level of transmission costs that would adversely impact their ratepayers and regional economic development efforts if the FERC adopts a socialized pricing regime for the corresponding level of new transmission investment that would be required to create the FERC's desired "interstate" highway system for electric transmission.

The various electric industry initiatives currently being pursued by the FERC raise challenging issues that do not need to be further confused by failures to articulate the actual differences between and among the various regions of the country. Representations that attempt to treat all areas of the country, or all state commissions, as one group, are inaccurate, frustrate any progress toward true dialogue, and inhibit the thoughtful consideration of actual problems and potential, appropriate solutions. The very real differences among the regions must be respected, considered carefully, and articulated by all involved parties for real understanding to occur and appropriate decisions to be made.

We appreciate the opportunity to clarify your testimony to the Senate Committee. You have undertaken an aggressive agenda at the FERC, and we appreciate this, and other opportunities, to participate in the dialogue.

---

efficiency alternatives, to be needed to maintain the reliability of the existing transmission system is recoverable through rates paid by all transmission customers; and be it further

RESOLVED, That the cost of upgrades and expansions that are necessary to support incremental new loads or demands on the transmission system are borne by those causing the upgrade or expansion to be undertaken except that the FERC should not preclude the assignment of interconnection cost to the general body of ratepayers within a State when that State's regulatory body determines that such allocation is in the public interest.

NARUC Resolution On Transmission Pricing Policy, Adopted by the NARUC Board of Directors at the February 2002 Winter Meetings in Washington, D.C.

The Honorable Pat Wood, III
August 22, 2002
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With best wishes and warm personal regards, I am

Sincerely yours,

James Y. Kerr, II
President

cc: The Honorable Linda K. Breathitt, Commissioner
The Honorable Nora Mead Brownell, Commissioner
The Honorable William L. Massey, Commissioner
Southeastern United States Senators
Southeastern Governors
Members, United States Senate Committee on Energy and Natural Resources
Member Commissions, Southeastern Association of Regulatory Utility Commissioners

EXHIBIT B

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
600 North Eighteenth Street P.O. Box 2641 Birmingham, Alabama 35291
Telephone: (205) 257-6407 Fax: (205) 257-0408
Web Page: www.sercl.org

William F. Reinke
Executive Director

Via Facsimile

August 28, 2003

The Honorable Billy Tauzin
United States House of Representatives
2183 Rayburn House Office Building
Washington, D. C. 20515-1803

Dear Representative Tauzin:

On behalf of the members of the Southeastern Electric Reliability Council I am pleased to respond to the questions concerning the events of August 14 posed in your August 20, 2003 letter. Please advise if you will require additional information from SERC concerning this event.

(1) *What were the basic causes and contributing events that led to the August 14th blackout and its severity? Describe the following in your answer:*
   a) *The location, character, and proximate cause of the initial disruption in the transmission and supply of electricity: and*
   b) *The "cascading" effect of the disruption through multiple utility systems and States.*

   The Southeastern Electric Reliability Council (SERC) has no unique information concerning this disturbance. The bulk electric systems in SERC remained intact during this event.

(2) *What efforts have been taken to secure the supply, transmission, and distribution since the blackouts of 1965 and 1977 in the Northeast, and why were these efforts apparently inadequate to prevent the blackout or otherwise minimize the area affected? What efforts have been taken in other parts of the country to prevent blackouts and how effective have these efforts been in preventing or minimizing blackouts?*

   SERC has no information as to why efforts were apparently inadequate to prevent the blackout or otherwise minimize the area affected.

Efforts that have been taken in SERC to prevent events described include: Creation of SERC in 1970. "SERC's purpose is to further augment the reliability and adequacy of bulk power supply in the areas served by the member systems. To this end the Council will:

a) promote the development of reliability and adequacy arrangements within the region;
b) participate in the establishment of reliability policies, standards, principles and guides;
c) participate in the measurement of performance relative to these policies, standards, principles, and guides;
d) ensure conformance to and compliance with these policies, standards, principles, and guides;
e) develop and exchange information with respect to planning and operating matters relating to the reliability and adequacy of bulk power supplies.;
f) review as necessary activities within the region on reliability and adequacy in order to meet expected standards and measurements;
g) provide a mechanism to resolve disputes on reliability issues in a manner that meets the needs of the parties and the region;
h) provide information with respect to matters considered by the Council, where appropriate, to the Federal Energy Regulatory Commission (FERC) and to other federal and state agencies concerned with reliability and adequacy;
i) take such actions as are necessary to adapt and put in place the Regional Compliance and Enforcement Program ("RCEP") contemplated by the April 25, 2001, "Agreement for Regional Compliance and Enforcement Program" between SERC and the North American Electric Reliability Council. Such action shall include, but not be limited to, preparing and entering into voluntary contracts with SERC Members establishing and governing RCEP standards and other matters, and adopting sanctions and processes for imposition of sanctions for noncompliance with RCEP standards."[1]

SERC Members have developed and implemented systems to protect the integrity of the bulk electric system for underfrequency events. Thirty percent or more of the connected load in SERC is subject to automatic

[1] Southeastern Electric Reliability Council Agreement dated January 14, 1970, amended October 23, 2002

underfrequency load shedding.

SERC has formally integrated Operations, Engineering, Markets, and Critical Infrastructure Protection in its committee structure.

SERC systems have integrated technological changes that enhance system reliability including:

- wide spread use of remote sensing technology
- implementation of System Control and Data Acquisition systems
- on line reliability tools including load flow and state estimator software

SERC systems have been aggressive in pursuit of improved planning and operations coordination including:

- Addition of a Conferencing Center to facilitate reliability: hotline calls; daily Reliability Coordinator calls; other member communications.
- Annual Emergency Plan Coordination Seminar
    - In preparation for the 2003 Emergency Plan Coordination Seminar SERC members' Under Frequency Load Shed information was gathered, consolidated, and distributed for discussion.
- Annual System Operator Conferences
    - Recognized and applauded by NERC
- Data bases for Transmission and Generation Outage Coordination
- Regional procedures and plans: emergency assistance procedures; black start regional restoration plan
- Participation in numerous and ongoing intra-regional and inter-regional analyses of projected operating conditions and long-term assessments of the reliability of the transmission system. SERC was a leader in first implementing inter- and intra-regional studies and analyses.
- SERC was a leader in developing and maintaining NERC Certified System Operators
- A SERC representative introduced the tagging concept to NERC, a fundamental tool widely used for congestion management.

SERC systems have also put in place an extensive program to assure compliance with NERC Operating Guides and Planning Standards. SERC audits control room operations in the Region on a three-year cycle to ensure that member systems comply with all applicable NERC standards. SERC has begun an audit process for compliance with NERC Planning

Standards with the intent of auditing its members on a three-year cycle for compliance with NERC Planning Standards.

- In 2002 SERC made more than1100 assessments of control room operations and found these systems to be 99.4% compliant with NERC Standards. None of the non-compliance findings affected or jeopardized the operation of the bulk electric system in SERC.
- Although the SERC Planning Standards Compliance Effort is less than five years old, it is more extensive than that recommended by NERC. Unlike operations, the NERC Planning Standards do not require quarterly or monthly assessments. Therefore, typically fewer planning assessments are performed. We are encouraged by the compliance findings to date and expect that as this effort matures SERC systems compliance with Planning Standards will exceed the 99+% target established by the operations groups.

3) *What equipment, measures, or procedures worked as intended on August 14th to prevent even greater disruption to the supply of electricity, to prevent greater damage to the generation and transmission system, and to bring generation back on line after the disruption?*

SERC system facilities all worked as intended on August 14. Any abnormalities observed on SERC system facilities as a result of the event were well within design parameters.

4) *How can the nation's electrical system, including both transmission capacity and reliability, be improved to prevent a recurrence of the events of August 14th? Please identify what measures may need to be taken by all involved in the governmental and nongovernmental sectors.*

SERC systems have developed a robust transmission system with more than 100 transmission connections to its neighbors to the north and west. SERC systems have experienced weather-related service disruptions, e.g., ice storms, tornadoes, hurricanes, but have not experienced an event similar to that of August 14.

Very truly yours,

William F. Reinke

William F. Reinke

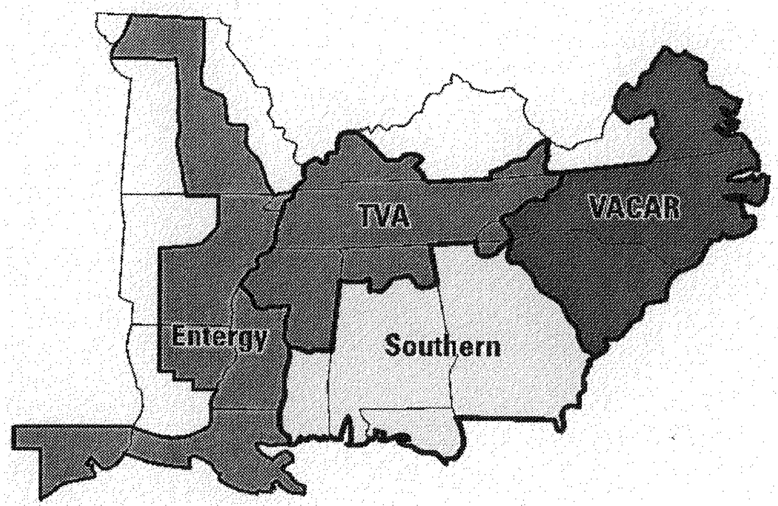
EXHIBIT C

SERC

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

Prepared for
The North Carolina Utilities
Commission
August 26, 2003

SERC Subregions



SERC Membership

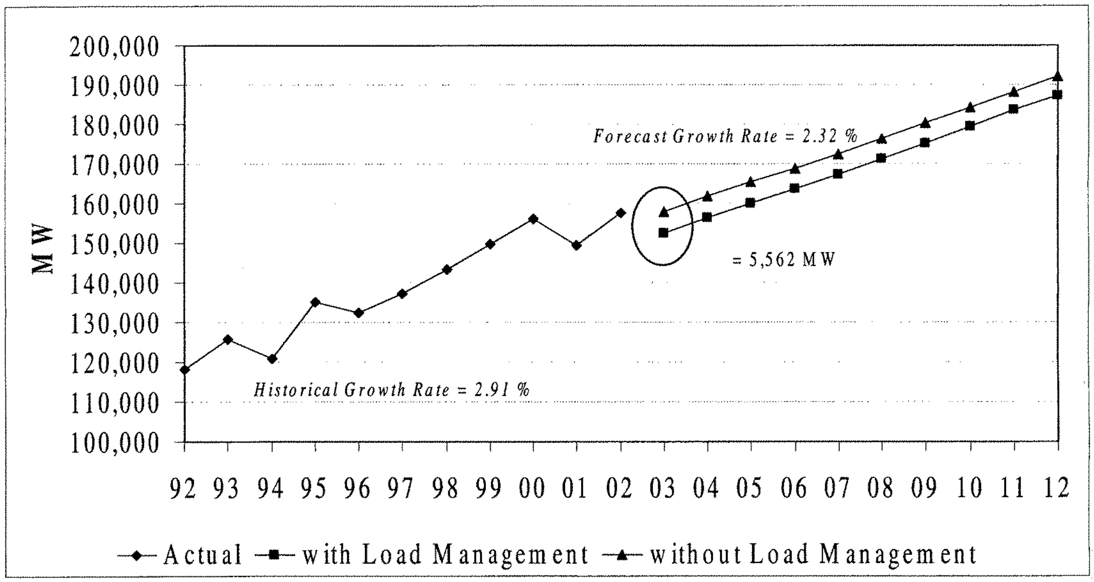
Investor-Owned Utilities (17) including:
- Duke
- Progress Energy
- Dominion
- South Carolina Electric & Gas

Cooperatives (8) including
- N C Electric Membership Corp
- Old Dominion Electric Cooperative

Municipals (6) including
- Fayetteville Public Works Commission
- NC EMPA
- NC MPA1

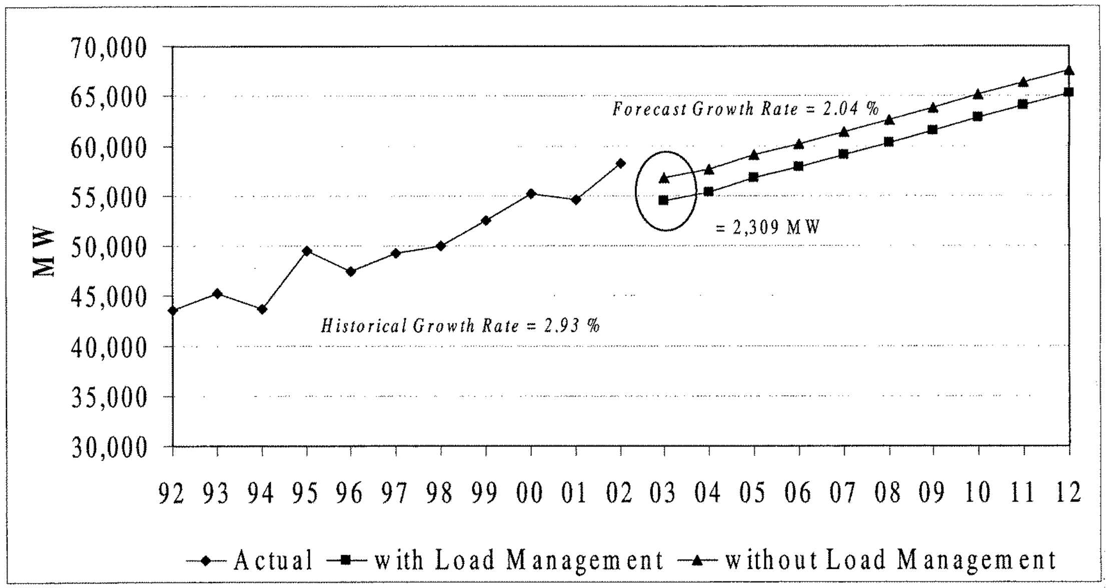
Federal/State Systems (4) including
- Santee Cooper
- SEPA

SERC Summer Peak Demand
Historical Actual vs. 2003 Forecast

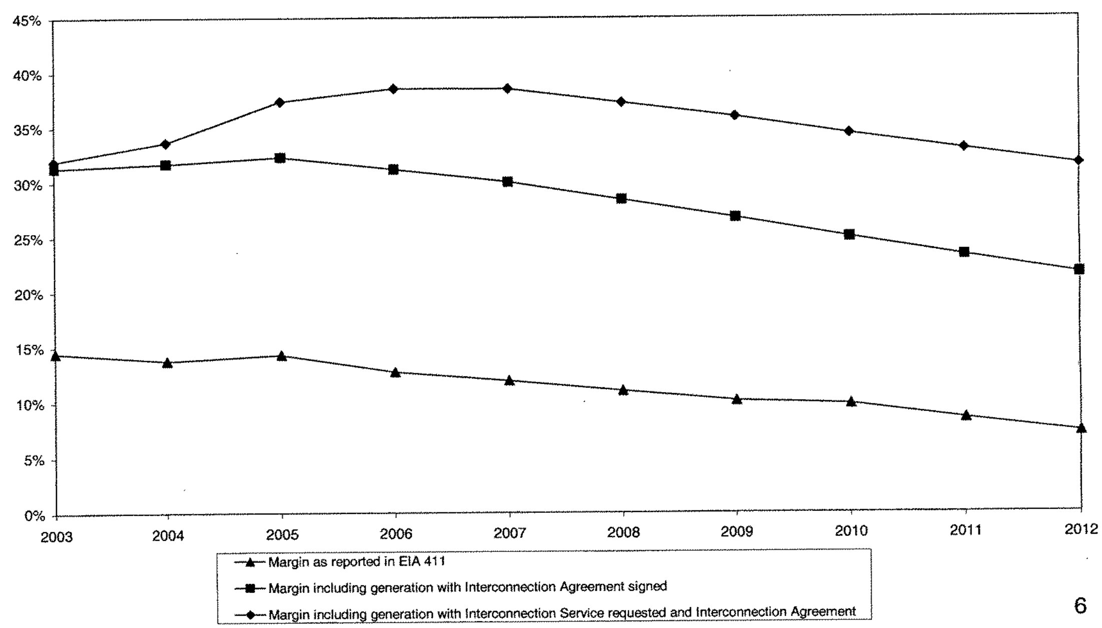


VACAR Summer Peak Demand

Historical Actual vs. 2003 Forecast



SERC Generation Development and Capacity Margins



SERC Generation Development

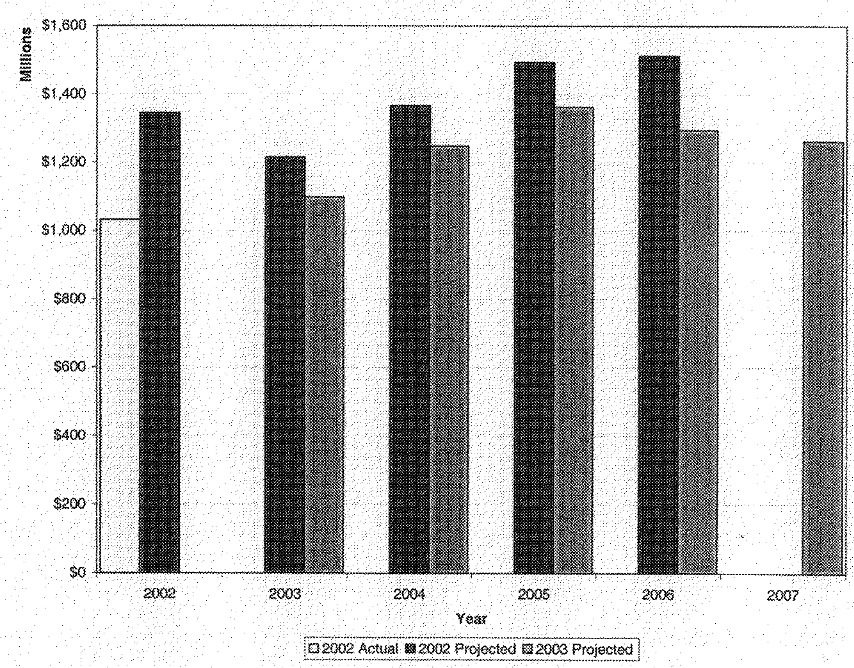
As of December 31, 2002:
- Total SERC Capability = 200,744 MW
  - Total Merchant Capability = 26,399 MW

Projected 2003 Peak SERC Demand = 152,442 MW

Additions through 2007 – SERC (VACAR)
- Interconnection Service requested = 33,046 (10,687) MW
  - Designated as a Network Resource = 12,486 (1,465) MW
- Interconnection Agreement signed = 38,381 (5,848) MW
  - Designated as a Network Resource = 9,988 (2,563) MW

Additions 2008-2012 – SERC (VACAR)
- Interconnection Service requested = 1,840 (320) MW
  - Designated as a Network Resource = 1,160 (320) MW

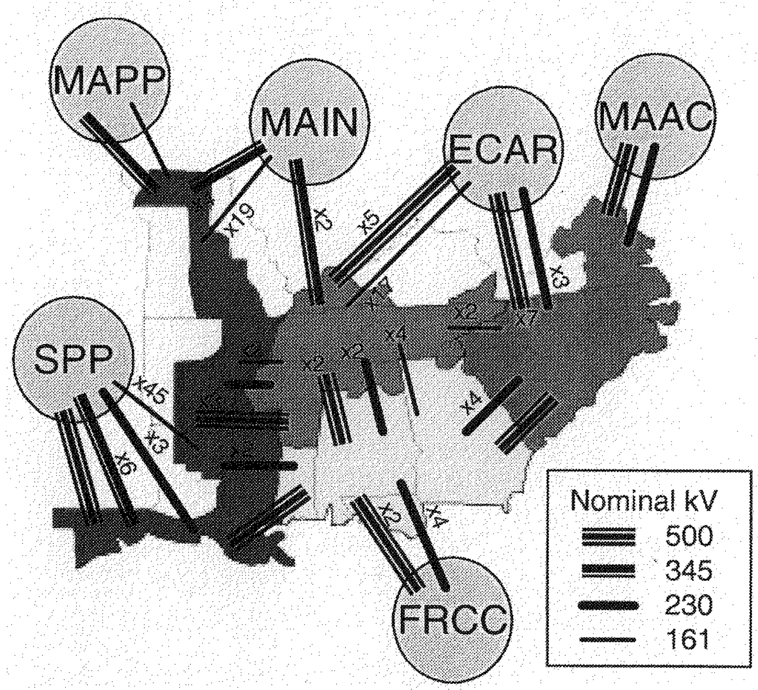
SERC Transmission Expansion and Improvements



SERC Transmission Expansion and Improvements

- Over $1 Billion invested in 2002
- Annual Investments through 2007 projected to exceed $1 Billion/year
- Five year total projected investments of over $6.2 Billion
- Approximately 3% related to new generation interconnections

SERC Interconnections



SERC Interconnections

61 interconnections to the North

55 interconnections to the West

6 interconnections to the South (FRCC)

24 interconnections between subregions and numerous others between SERC members

SERC Coordination Efforts

- SERC Conferencing Center
  - Reliability Hotline Call
  - Daily Reliability Coordinator Call
  - Other member communications
- Annual Emergency Plan Coordination Seminar
- Annual System Operators Conferences
- Transmission Outage Coordination
- Provisions made for future Generation Outage Coordination
- Region Procedures and Plans
  - Emergency Assistance Procedures
  - Blackstart Regional Restoration Plan
- SERC Operating Policies Manual contains supporting documentation and information to facilitate these coordination efforts, including an Emergency Plan Contact List

Coordinated Analysis

- Intra-Regional
  - VAST Winter Reliability Study of Projected Operating Conditions
  - VAST Summer Reliability Study of Projected Operating Conditions

  Inter-Regional
  - MAIN Winter Transmission Assessment Study
  - MAIN Summer Transmission Assessment Study
  - VEM Winter Interregional Transmission System Reliability Assessment
  - VEM Summer Interregional Transmission System Reliability Assessment
  - Southern – FRCC Winter Interface Study
  - Southern – FRCC Summer Interface Study

  Other special studies as necessary

SERC Compliance Program

Planning

Operating

Audits

Monitors compliance with SERC requirements, NERC Planning Standards, and NERC Operating Policies.

EXHIBIT D

Northeast Blackout
August 14, 2003

Presentation to the
North Carolina Utilities Commission
by
Progress Energy, Dominion, and Duke Energy
August 26, 2003

Dominion

Duke Power®
A Duke Energy Company

Progress Energy

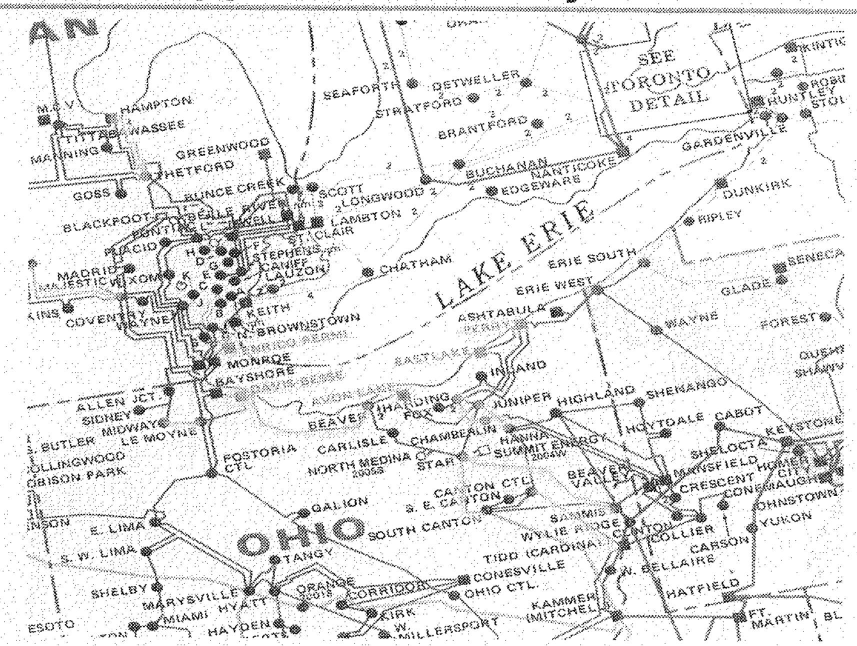
Agenda

- What happened and why?
- How did we respond?
- How do we best protect against a similar event occurring here?

What happened and why?

- Blackouts can be caused by
  - Operating beyond first contingency
    - systems are operated to withstand the single worst contingency at all times (loss of a generator, transformer, transmission line)
  - Imbalance between generation and demand
    - high frequency, low frequency, or voltage collapse
    - transmission overloads
    - generating unit trips
  - Multiple near simultaneous contingencies (loss of multiple elements)
    - sabotage
    - severe weather
    - human error
    - equipment failure

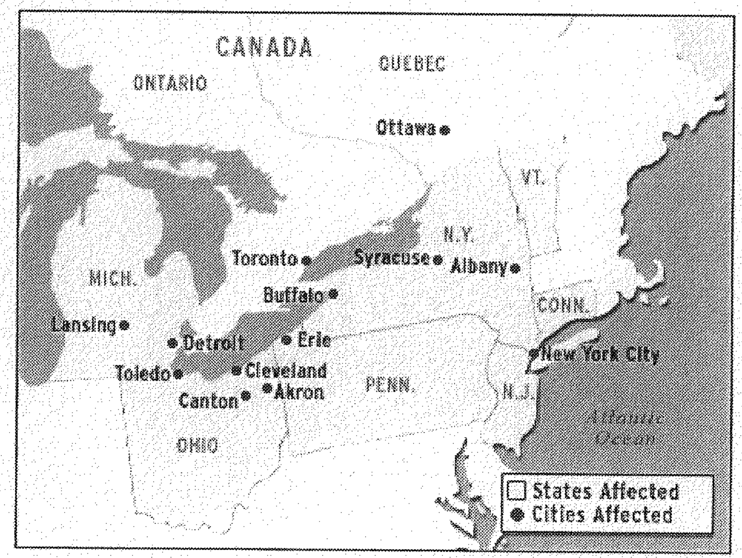
What happened and why?



What happened and why?

- Total - 61,800 MW lost
  - PJM Interconnection (RTO) – 4,200 MW
  - Midwest ISO (RTO) – 13,000 MW
  - Hydro Quebec – 100 MW
  - Ontario IMO – 20,000 MW
  - ISO New England (RTO)– 2,500 MW
  - New York ISO (RTO) – 22,000 MW

What happened and why?
Affected Areas



What happened and why?

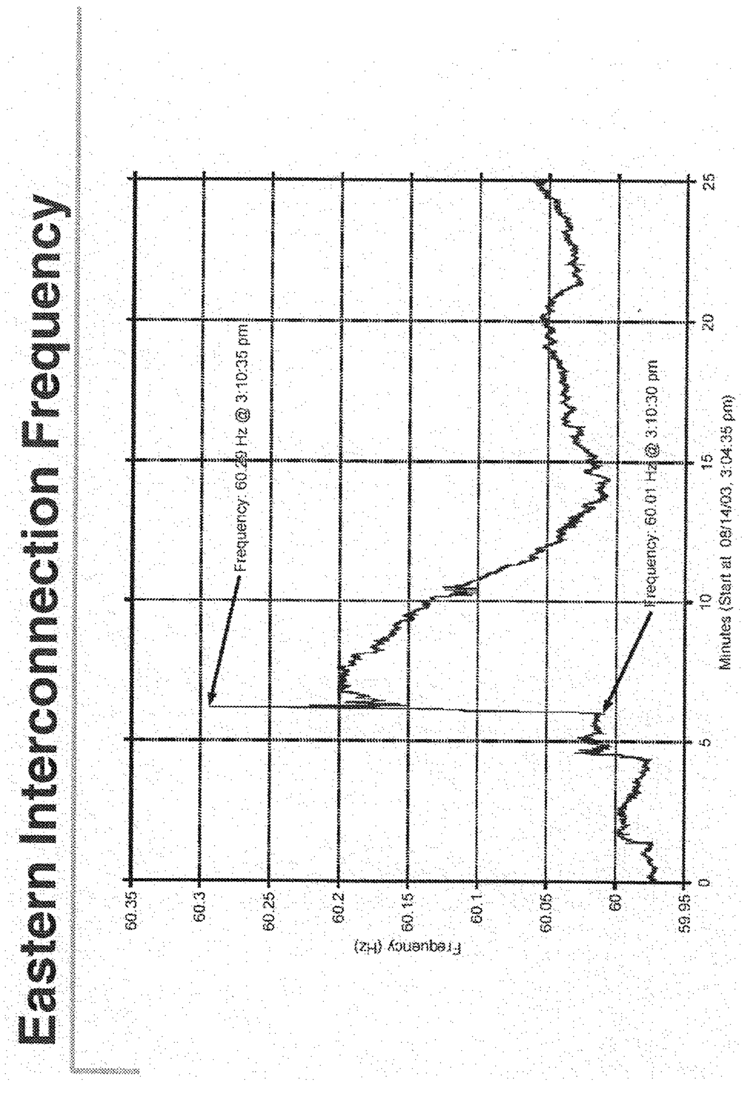
- Lots of speculation at this point
- Investigation will determine what happened
- Questions that will be answered
  - What was the initiating event?
  - What caused the transmission lines to trip?
  - Was the system being operated beyond its limits?
  - Was the System Operator unaware or slow to recognize the problem or to take action?
  - Was there effective communication before and during the event?
  - We just don't know yet !

How did we respond to this event?

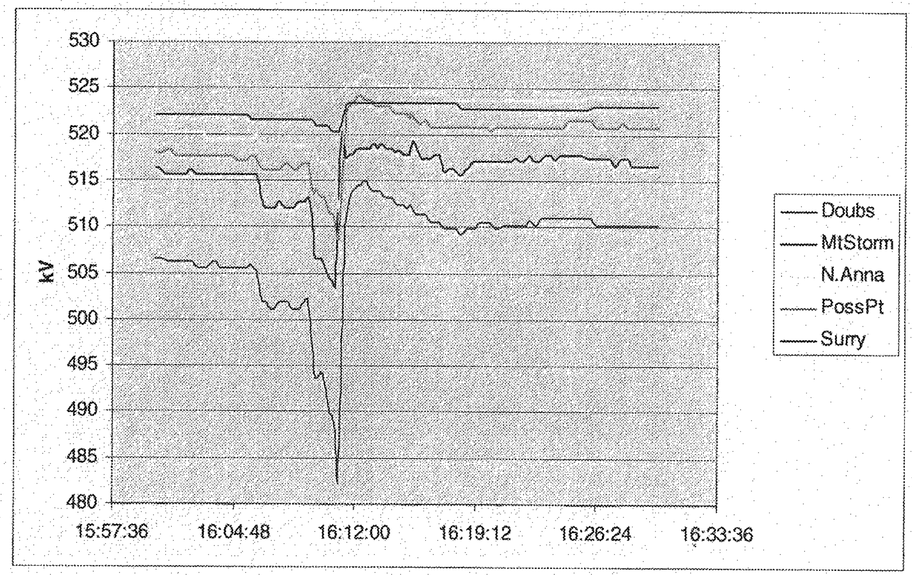
- Our power systems reacted as designed
  - Automatic voltage regulators on generators boosted voltage as needed
  - Generators reduced output to slow system frequency
  - The metered flows on our tie-lines fluctuated within design limits
  - No automatic tripping of transmission system elements

How did we respond to this event?

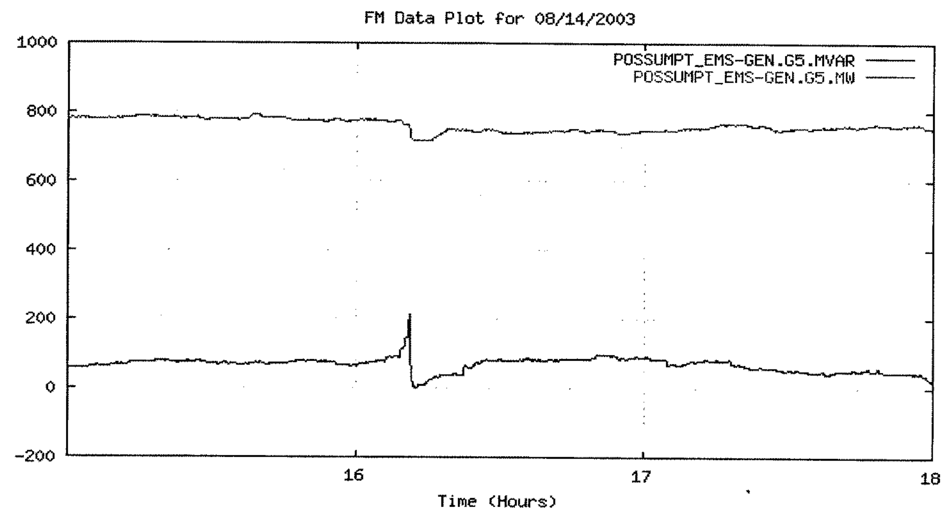
- Our operators took appropriate actions
  - Communications with neighboring systems
  - Maintained the interconnection
  - Allowed automatic actions to complete the stabilization of remaining Eastern Interconnection
  - Ensured secure operations during recovery of the load
- Our external relations staffs answered questions from numerous customers and media
  - Made Operating Personnel available to help the media explain the event to the public
  - Invited TV stations in to cover system operations
  - Avoided speculation on cause of event


Eastern Interconnection Frequency
Frequency (Hz)
60.35
60.3
60.25
60.2
60.15
60.1
60.05
60
59.95
0
5
10
15
20
25
Minutes (Start at 08/14/03, 3:04:35 pm)
Frequency: 60.29 Hz @ 3:10:35 pm
Frequency: 60.01 Hz @ 3:10:30 pm

500 kV Voltage Fluctuations



Example of unit response - Possum Point 5



How do we best protect against a similar event occurring here?

- Starts with Good Planning
  - Diverse generation
    - Adequate capacity margin
  - Strong transmission system
    - Adequate transmission capacity margin
  - Coordinated plans and protective systems
- Good Operations
  - Diligent monitoring and control of the system
  - Comply with reliability rules
    - VACAR companies are using the transmission system as designed
    - Actively participate in development of the standards
  - Operate the equipment within design parameters
  - Continue prudent maintenance practices

How do we best protect against a similar event occurring here?

- Ensure we have highly trained employees
  - Ongoing Operator Training
    - NERC Certification
  - Learn from this event
- Seamless Coordination
  - Constant Control Room-to-Control Room communication
  - VACAR Reserve Sharing
  - VACAR Reliability Agreements
  - VACAR Transmission Coordination
- VACAR Reliability Coordinators

Summary

- Why the blackout in the Northeast occurred is not yet known
- Our systems are planned and operated to prevent such a blackout
  - We have adequate generation and transmission
  - Our personnel are highly trained
  - We have state of the art control centers
- Systems through the Southeast are highly coordinated
- We are confident we can operate our systems in a reliable manner

Consumer Federation of America

Consumers Union
Publisher of Consumer Reports

THE FEDERAL RESPONSE TO THE 2003 BLACKOUT: TIME TO PUT THE PUBLIC INTEREST FIRST

STATEMENT OF DR. MARK N. COOPER

**Subcommittee On Oversight Of Government Management,
The Federal Workforce And The District Of Columbia
Committee On Governmental Affairs, United States Senate
SEPTEMBER 10, 2003**

MR. CHAIRMAN AND MEMBERS OF THE COMMITTEE,

My name is Dr. Mark Cooper. I am Director of Research at the Consumer Federation of America (CFA).[1] I also appear today on behalf of Consumers Union.[2] We have been deeply engaged in the debate over electricity restructuring and deregulation for almost two decades. I have submitted to you a list of appearances I have made before Congress and Federal Agencies, as well as state regulatory commissions, on this issue. I have also submitted the ~~studies and analyses of the faltering efforts to deregulate electricity, which we have conducted~~ since 1997, soon after the first radical restructuring laws were passed in a couple of states. Every six months for the last twenty years we have been cautioning policymakers not to experiment with electricity or treat it like any other commodity.

I greatly appreciate the opportunity to appear before you today to present the residential ratepayer view of the federal role in the ongoing troubles of deregulated electricity markets. It is about time that the voice of the little guy and gal, the people who pay the bill, is heard on this matter. It is about time that you get the perspective of local jurisdictions that have had the good sense not to go down the road of electricity restructuring and deregulation or have decided to change course after being badly burned by deregulation and restructuring. Two-thirds of the states have figured out that deregulation is a road to ruin. It is time for federal authorities to change course too, or at least to pause for a substantial period while they rebuild the physical and institutional infrastructure of the electricity gird.

ELECTRICITY RESTRUCTURING DOES NOT ADD UP FOR RESIDENTIAL CONSUMERS

In the wake of the massive blackout in the Northeast, government officials and industry experts are calling for a massive upgrade of the transmission system that will cost between $50 billion and $100 billion. The annual carrying costs for such a capital outlay are certain to be in the range of $10 billion to $25 billion, or even more if the merchant model being pushed by the

[1] CFA is the nation's largest consumer advocacy group, a non-profit association of 300 pro-consumer groups, with a combined membership of 50 million, founded in 1968 to advance the consumer interest through advocacy and education.

[2] Consumers Union is a nonprofit membership organization chartered in 1936 under the laws of the State of New York to provide consumers with information, education and counsel about goods, services, health, and personal finance; and to initiate and cooperate with individual and group efforts to maintain and enhance the quality of life for consumers. Consumers Union's income is solely derived from the sale of *Consumer Reports*, its other publications and from noncommercial contributions, grants and fees. In addition to reports on Consumers Union's own product testing, *Consumer Reports*, with approximately 4.5 million paid subscribers, regularly carries articles on health, product safety, marketplace economics and legislative, judicial and regulatory actions which affect consumer welfare. Consumers Union's publications carry no advertising and receive no commercial support.

Federal Energy Regulatory Commission (FERC) is pursued. Many experts are beginning to admit that a substantial part of the upgrade costs are caused by the need to support the increased strains on the system that occurs in deregulated electricity markets. In contrast to these huge costs, the Department of Energy conducted a study earlier this year using extraordinarily optimistic and unfounded assumptions but still projected less than $1 billion of efficiency gains from implementation of FERC's Standard Market Design. FERC's own study found equally meager gains, while studies by other regulatory commissions question whether even those small benefits are realistic.

A consumer does not need a degree in electrical engineering to see that these numbers do not add up. If the costs outweigh the benefits, why should we bother? At a minimum, policymakers should inquire as to what it would cost to run a reliable system without the added demands on the system and associated costs of supporting deregulated markets.

Frankly, with the discovery of massive infrastructure costs needed to support deregulation and the run up in natural gas prices, there is no chance that deregulation will produce benefits for the vast majority of residential consumers. In the northeast and mid-west where regulators did a miserable job of protecting consumer interests in the 1980s and 1990s, it was possible to use regulatory mechanisms to hold consumers harmless during the early phase of deregulation, but those days are gone. Consumers now face huge price increases as the dash to gas–fired generation in the past decade will flow through to the electricity meter and meet up with the excessive capital costs of deregulated markets.

ELECTRICITY IS A UNIQUE AND VITAL SERVICE, NOT JUST A COMMODITY

This is not the first time that the electricity market has thrown a curve at deregulation. In fact, restructured electricity markets have lurched from crisis to crisis – the price spikes of 1998, the outages of 1999, and the California meltdown of 2000-2001. All of these events share a common cause – electricity is different from any other service or commodity.

Historically, the uniquely American approach to delivering this vital and difficult service was to allow private companies to own both transmission and generation and provide service in exclusive territories, subject to public interest obligations. The integration of generation and production fostered coordination and effective management of the network. Exclusive territories lowered the risk and costs associated with long-term inflexible assets. Public interest obligations, such as the obligation to serve all customers at just and reasonable rates, protected the public from the abuse of monopoly power while preserving companies' incentive to invest in the network.

This pragmatic approach was certainly not perfect, but it achieved a critical balance between public and private interests. In the past decade, policymakers lost sight of these fundamentals and deregulation upset that balance, particularly for the transmission system. De-integration quickly turned into disintegration.

Electricity has no substitutes. It is not storable. It is essential to health, safety and the economy. It must be delivered under incredibly demanding conditions through an extremely capital intensive infrastructure.

It was blatantly irresponsible for Federal and state authorities to rush ahead with deregulation without the necessary physical and institutional infrastructure to support the markets they were trying to create. It would be grossly negligent for Congress to allow restructuring to continue without taking a long pause to repair the damage that has been done to consumers and the electricity infrastructure.

RESTRUCTURING AND DEREGULATION MAKE IT MORE DIFFICULT TO ENSURE RELIABILITY

Make no mistake about it; deregulation and restructuring have increased the stress on the transmission system. There are numerous economic and operational mechanisms through which electricity restructuring and deregulation increased pressures on the nation's electricity transmission network:

- A dramatic increase in the number and complexity of transactions, which the system was not designed to support.
- Difficulties of coordination and planning as competition and contracts replace vertically integrated operational and administrative decisions.
- Deregulation short-circuited utility incentives to invest in transmission because the private interests of facility owners came into conflict with the shared, public nature of the transmission grid and created a disincentive to spend on maintenance because of profit pressures and the perceived competitive disadvantage associated with spending on a system shared with potential competitors.
- Increasing needs for excess capacity to cope with market manipulation problems that plague electricity markets and to dampen price spikes that result from trying to treat electricity like a commodity, all of which must be paid for with the higher cost of merchant finance.
- Failure to account for the social and environmental constraints on increasing transmission capacity and to provide a framework for comprehensive planning that integrates alternative approaches, like energy efficiency and local (distributed) generation (such as co-generation).

Given the massive costs of deregulated markets that are now coming into view and the meager gains that such markets appear to promise, not to mention a track record of market manipulation, price volatility and lack of consumer choice, it may be a lot cheaper for the handful of states who have deregulated to go back than to force the majority of states down the problem riddled road toward deregulation.

THE GRID IS BASIC INFRASTRUCTURE: A HIGHWAY, NOT A MARKET

Transmission facilities are critical infrastructure of a modern society and digital economy that must be dedicated to promoting the public interest. They are part of a shared system in which the fate of each user and producer is tied to the behavior of others. The fundamental problem with transmission is not inadequate economic incentives to invest; utilities were willing to do so before deregulation the problem is public resistance to the building of additional transmission lines for environmental, health and safety reasons. The social cost of transmission facilities is far greater than their economic costs. For this reason, scarcity of transmission in the economic sense is likely to be a permanent part of the industry landscape.

Moreover, the benefits of shared transmission facilities that support the overall network are difficult to align with private calculations of costs and benefits. The problem is both geographic, determining which benefits accrue to which areas, and intergenerational, recognizing that different parts of the system may benefit differently from the same investment across time. Today's investment to serve a long distance transaction may be a core part of tomorrow's system serving native (local) load. The shared nature of facilities makes it more difficult for private investors to recover their costs and to overcome the social resistance to the siting of facilities. The shared nature of facilities across jurisdictions makes it more difficult to reconcile competing interests. Such public investment is best carried out within the framework of a comprehensive plan. Yet, integrated resource planning is harder to implement in the deregulated model, if it is not abandoned altogether.

We take the primary lesson of the decade of deregulation to be that we need to restore the balance of public and private interests in the electricity sector. Society cannot rely on private actors to ensure that adequate investments are made in vital public goods, such as the electric transmission grid. The transmission system is a highway, not a market, and should be developed under a public interest model in which the primary purpose of all participants is to ensure reliability and protect the public. The obligation to serve, which transmission utilities properly bear, must be matched with a duty to build. Bribing merchants to provide these vital public goods, such as through "incentive" payments, unbridled expansion into non-utility businesses, and the auctioning of transmission capacity to the highest bidder, will be particularly expensive.

These lessons have been clear for quite some time. Federal authorities simply seem unwilling to get the message. Two years ago, in the midst of the last crisis of electricity restructuring and deregulation, in testimony I entitled "The Federal Role in the Deregulation Tragedy," I offered the following conclusions about transmission:

> The failure to recognize the important role of the continuing monopoly in transmission resulted in the under-regulation of the wires segments of the industry. The transmission wires are the highways of commerce over which electricity flows. This is a highway system, not a market, which constitutes an essential, bottleneck facility with virtually no redundancy and never likely to support head-to-head competition. One of its primary inputs is right-of-way, which relies on governmental power of condemnation. The biggest obstacle to the expansion of transmission capacity is a social externality – public concern about ugly wires and local health effects – not inadequate economic incentives. Proposals to let the marketplace solve the wires problem are not likely to succeed, since given the market power that the wire "owner" would possess and the non-market barriers to expanding capacity, profit maximization would only result in the abuse of market power and the creation of artificial scarcity rents.
>
> The right model for transmission is a public or private entity imbued with the public interest and dedicated to ensuring that this essential facility fulfils its public functions – ensuring reliability and supporting nondiscriminatory market transactions in the widest area possible to achieve economies of coordination and maximum competitive effect. It must be independent of market participants and directly accountable to public authorities for achieving those goals. Transactions must be standardized and transparent, with the creation of an exchange in which all rates terms and conditions can be identified. Brokers must

be subject to rules that are similar to those applied to financial transactions like stock sales.

We offered similar advice to the Congress last year in a report entitled "All Pain: No Gain:"

> Rather than rushing ahead with restructuring and deregulation, Congress and FERC need to step back and fully understand the implications of the abuses, operational disruptions, and the financial crisis that has occurred in the electricity industry. Congress must restore simplicity and transparency to the industry. The first goal must be to reinforce consumer and investor protections. A comprehensive review of the national transmission system should be conducted. Effective mechanisms for planning and expanding the grid should be demonstrated in reality. Institutions for managing the grid and overseeing trading should be transfigured before moving forward.

I could go back two decades and the message would be the same. I understand the pressures to do something in the wake of the blackout, but when it comes to electricity, doing just anything will not help. You have to do the right thing, or you will make matters worse.

WHAT FEDERAL AUTHORITIES SHOULD NOT DO

~~Policymakers could have eased the transition to competitive generation markets by~~ recognizing the physical and institutional infrastructure that would be needed to support greater competition, but they did not. Perhaps they realized that presenting a true picture of the difficulty of electricity deregulation would have made it impossible to sell to the public. Whatever the reason behind the underestimation of the difficulties of deregulation, the build-up of problems now makes the implementation of competition a much riskier proposition. Not only has the inadequacy of institutions and facilities grown, but public confidence in the process has also been eroded. Congress needs to start solving the problem by stopping the deregulation train.

Do not repeal the Public Utilities Holding Company Act (PUHCA). Congress does not need to allow utilities to diversify into non-utility businesses and form huge multi-state holding companies by repealing PUHCA to solve the reliability problem. This would subject the utility industry to less oversight, by allowing utilities to play a shell game with their assets and increasing FERC's responsibility, which has so far been completely unable to deal with the manipulation of markets in the west and with the misreporting of energy prices.

Do not allow the FERC to impose its complex "Standard Market Design" on the nation. Regional transmission organizations that are dominated by industry and preempt local accountability while forcing utilities into markets that allocate transmission resources to the highest bidder, with no assurances that transmission is presently adequate or that additional transmission capacity would be built or adequately maintained, are a prescription for disaster.

Do not rely on industry self-regulation for reliability. The proposal to move from voluntary *self-regulation* to mandatory *self-regulation* misses the point. The problem is not the voluntary part; it is the *self-regulation* part. The industry will simply not regulate itself sufficiently, especially in a market-oriented system, to protect the public. The private interests of the large players will always come first.

Do not create private transmission monopolies. Transmission services are a natural monopoly and part of a shared network. Transferring control to unregulated private parties will simply allow them to abuse captive customers and shift costs onto the backs of ratepayers throughout the system.

WHAT FEDERAL AUTHORITIES SHOULD DO

Federal authorities should devote all of their energy to promoting the public interest, not the profits of merchant generators and transmission owners, by studying, strengthening and managing the interstate transmission system. **Any interstate transmission organization must be based on fairness and public accountability.** We must create new institutions that can reconcile the interests of the states and include representation of consumer interests. Interstate compacts or federal state-joint boards are a possibility.

Fairness requires that an interstate transmission organization embody a process for fair representation of all interests affected by transmission projects. Local consumers and citizens must not be excluded from the process. **Accountability** demands that local officials who get the phone calls when the lights go out must be in a position of authority. Standards must be set by responsible authorities and be mandatory, with stiff penalties for failure to comply. Industry self-regulation will not do. Public accountability also requires **transparency**. The competition between the FERC and the DOE, and the army of private consultants muddying the picture of what happens on the transmission grid, is unacceptable.

The obstacle to expanding transmission is not inadequate economic incentives; the obstacles are environmental, public health, and safety concerns. Even if economic incentives were a problem, **the solution is not to increase incentives; it is to lower risk**. The cost of bottleneck, infrastructure facilities are much lower when they are funded through a utility finance model. Utility investments in transmission facilities will easily attract capital if policy makers restore their traditional quality of stable, dividend paying investments.

Congress should require a framework for **comprehensive planning that considers all alternatives**. It should **get serious about energy efficiency**, like mandating higher minimum standards for air conditioners, which would reduce demands on the grid at its most vulnerable times, hot summer days. It could also **give a boost to local (distributed) generation**, which has the double benefit of adding generation resources to the system while not using long distance transmission lines, whose failure triggered the recent blackout.

Unfortunately, both the House and Senate bills that are being reconciled in conference violate virtually every one of these consumer "Do's" and "Don'ts." The fact that the Congress has failed to act in the past several years is actually a good thing for consumers because Congress has never once come close to passing legislation that would do the right thing. Now is the time to focus on the real problem, restore accountability and oversight over the industry and put the public interest first.

Testimony of Pat Wood, III
Chairman, Federal Energy Regulatory Commission
Before the Subcommittee on Oversight of Government Management,
the Federal Workforce, and the District of Columbia,
Committee on Governmental Affairs
United States Senate
November 20, 2003

Mr. Chairman and Members of the Subcommittee:

Thank you for the opportunity to appear before you today to discuss the findings and recommendations of the interim report of the joint U.S.-Canada Task Force on the August 14, 2003 Northeast blackouts.

Watching and studying this blackout has been a sobering experience. The reliability of the North American electric system is normally so excellent that this year's notable service interruptions – from the August 14 blackout in the Northeast, blackouts in London, Italy, Argentina, Norway, and elsewhere, and recently from Hurricane Isabel – have forced us all to look afresh at all our old assumptions about the value of reliable electric service and what it takes to keep the lights on.

Here's what I have learned from the blackout investigation and this interim report, and from thinking about those other blackouts this year:

The blackouts in the Northeast, Italy, London and elsewhere have a common theme – something routine happens, like a tree contacting a powerline or a minor relay setting done wrong, and the time to react and keep the system stable suddenly shrinks beyond the capability of human control, when the machines take over. The grid is a tremendously complex system, and the interconnectedness that allows us to benefit from higher reliability and lower costs also causes the domino failures experienced in many countries in recent months. We cannot ever prevent blackouts, but we can and must learn to reduce their frequency, magnitude and impact.

The best way to manage blackouts is to prevent them, not to hope for heroic rescues when we're already in a jam. The secret to reliability lies in making sure that <u>every</u> transmission owner, control area operator, and reliability coordinator takes care of the basics – adequate tree trimming, adequate training for emergency as well as routine operations, effective communications within and across organizations, and having effective back-up facilities, procedures and tools. The investigation clearly shows that had FirstEnergy trimmed its trees, used a solid state estimator program after the trip of the Eastlake 5 unit and regularly throughout the afternoon of August 14, and trained its operators better to recognize and deal with emergencies, the blackout would not have happened.

The blackout study shows that current reliability standards were violated by FirstEnergy and the Midwest Independent System Operator. We need better compliance and tough, clear standards. The FERC will be working closely with NERC and the stakeholders to develop those standards and to implement the reliability provisions of the energy bill if Congress approves it.

We do need some major investments in new transmission facilities and new grid technologies, especially those that make it easier for us to manage the basics. But we need to make those investments wisely, for lines and equipment that expand the reliability parameters of the grid where it is needed – for instance, new sources of reactive power for the Cleveland-Akron area – appear to be long-overdue. Further analysis conducted by the blackout investigation teams will teach us much about how the cascade spread and why it stopped where it did, and that will help us design a system that over the longer term should perform more reliably and cascade more narrowly. The new energy bill offers new options to site long-needed transmission lines and to pay for reliability investments, and I am eager to put those measures in place.

We also need to invest in hardware and software that let operators manage the grid more effectively. Tools that improve system monitoring, evaluation, visibility, visualization and information sharing about grid conditions over a wide region will allow operators to manage the grid more reliably on a day-to-day basis as well as in emergencies. Our colleagues at the Department of Energy have done some excellent work in this area over the past few years and we will be looking to these technologies and others to raise the bar for grid management capabilities.

Transmission is regulated at the federal and state level. Clearly we need to regulate it better, to assure the reliability that Americans deserve. As the present energy bill recognizes, the days of voluntary reliability standards with no enforcement teeth must end. Federal regulators must work closely with our state colleagues to make sure that utility cost-cutting that allows 14 inch diameter trees to grow in transmission rights-of-way, or inadequate operator training, or the widespread use of inadequate software ineffectively used, must end. I pledge that my commission will work closely with our colleagues in Ohio and other states to deliver better regulation for better reliability.

Some claim that electric competition and higher energy flows caused under-investment in an over-worked grid and made this blackout inevitable. What they ignore is that the operator's primary charge is to work the system you've got, and that the operator has the power to cut back any transaction, tighten the operational limits on any line or power plant, and even cut customer load, if that's what it takes to keep the system safe and secure. Markets do not compromise reliability, but we must redouble our efforts to assure that all necessary reliability measures are taken.

Perhaps the saddest portion of the blackout report is Chapter 6, the comparison of the August 14 outage to other major outages in North America. The common factors are overwhelming:

- Conductor contact with trees due to inadequate vegetation management
- Insufficient reactive power
- Inability of system operators or coordinators to recognize and understand events across the broad regional system
- Failure to ensure that system operation was within safe limits
- Lack of coordination on system protection
- Failure to identify emergency conditions
- Ineffective communication
- Lack of "safety nets", and
- Inadequate training of operations personnel.

The seven outages reviewed span from 1965 through 1999. Extensive analysis followed each outage, and blue ribbon panels developed good recommendations after each. Some of the recommendations that followed that outage have been implemented, but not many. It is my hope that with the adoption of the new reliability provisions of the energy bill, we can finally implement most of those recommendations and stop making the same mistakes over and over. The cost of those mistakes is too high, and our nation and our people deserve better.

The cost of major blackouts is immense, in human and financial costs. New transmission facilities and tools – AC and DC lines, substations, capacitors, sensors, state estimators, visualization programs, and others – are not cheap. Business practices that improve transmission reliability – like thorough tree-trimming, operator training, and development of procedures and plans for routine and emergency communications – are not cheap either, and will cost more on customers' bills. But if you ask the New Yorkers who were stuck in the subway on August 14, or the Cleveland residents who had to boil their water for days, or the folks around Maryland and Virginia who sat without power for as long as a week after Hurricane Isabel, most will tell you that they'd rather pay a little more for electricity if it will reduce the number, length and impacts of such outages. The cost of reliability improvement is trivial in comparison to the costs and consequences of poor reliability, and we need to be less penny-wise and pound-foolish when we do this math.

Thank you. I will be pleased to answer any questions you may have.

Testimony of James W. Glotfelty
Director, Office of Electric Transmission and Distribution
U.S. Department of Energy

Before the
U.S. Senate Committee on Governmental Affairs
Subcommittee on Oversight of Government Management, the Federal Workforce, and the District of Columbia
Washington, D.C.
November 20, 2003

Mr. Chairman and Members of the Subcommittee:

Thank you for the opportunity to testify here today and outline the findings of the U.S.- Canada Power System Outage Task Force investigating the blackout on August 14, 2003.

Three months ago today, large sections of the United States and Canada were still recovering from one of the largest power blackouts in our nation's history. Since the blackout, hundreds of technical experts have worked tirelessly to help the U.S-Canada Task Force determine how and why it occurred.

Yesterday, the Task Force released an Interim Report that marks our progress to date in the search for answers about what happened that day.

This Interim Report focuses on the events, actions, failures, and conditions that led to the blackout and caused it to cascade over such a large region, as well as questions relating to nuclear power operations during the blackout and to the security of the grid control systems

It presents facts collected by the investigation team and does not offer speculative or unconfirmed information or hypotheses.

Without going though a line-by-line review of how the system failed that day, I would like to walk you through the three causes of this blackout.

Before I do this, I want to make clear that it is the control area operators who have the primary responsibility to maintain system reliability, regardless of conditions. They are required to have the tools to ensure the grid is reliable. There were three groups of causes:

Group 1 - FirstEnergy didn't properly assess changing conditions on its system, which degraded as the afternoon progressed. In particular:

- FE didn't ensure the security of its transmission system because it didn't use an effective contingency analysis tool routinely.
- FE lost its system monitoring alarms and lacked procedures to identify that failure.
- After efforts to fix those alarms, FE didn't check to see if the repairs had worked.
- FE didn't have effective backup monitoring tools to help operators understand system conditions after their main monitoring and alarm tools failed.

Group 2 - FE failed to adequately trim trees in its transmission rights-of-way.

- Overgrown trees under FE transmission lines caused the first three FE 345 kV line failures.
- These lines tripped when contacting trees that had grown past their maximum allowable limits in their rights of way.
- Trees found in FE right-of-way areas are not a new problem
  - The investigation found one tree over 42' tall; one 14 years old; another 14 inches in diameter were found in FE rights-of-way.
  - There also was extensive evidence of prior tree-line contacts.

Group 3 - Reliability Coordinators did not provide adequate diagnostic support to assist FE in responding to problems.

- MISO's state estimator failed because of a data error.
- MISO's flowgate monitoring tool didn't have real-time line information to detect growing overloads. (The flowgate tool was still under development at the time of the blackout.)
- MISO operators couldn't easily link breaker status to line status to understand changing conditions. (The EMS tool was still under development at the time of the blackout.)
- PJM and MISO lacked joint procedures and wide grid visibility to coordinate problems affecting their common boundaries.

According to NERC, these failures violate a number of reliability standards. Specifically,

- FE violated at least four NERC reliability standards.
- MISO violated at least two standards.

A critical reference point in this investigation is 3:05 p.m. At that time, the investigations extensive modeling determined that the system was capable of being operated reliably. That fact alone eliminates a number of possibilities as causes of the blackout. They include:

- High power flows to Canada,
- System frequency variations,
- Low voltages earlier in the day or prior days,
- Low reactive power output from IPP's, and
- Existing outages of individual generators or transmission lines that had occurred well in advance of the blackout.

Finally, the Task Force report finds that:

- Procedures at the nuclear plants were followed and worked well on August 14th.
- The nuclear plants all shut down safely when they detected a disturbance,
- And were restarted safely when the grid was restored.
- In addition, no deliberate damage or tampering has been found in any equipment in affected areas of the grid.
- And no computer viruses or any sort of illicit cyber activities have been identified as factors.

In closing, Phase One of our Task Force investigation, and the public's response to it, will give us a wealth of information that will be the basis for formulating recommendations on ways to make our electric system stronger.

Phase Two of this investigation will include three public forums in Cleveland, New York City and Toronto. These public forums will offer an opportunity to all of those listed in this report, as well as other interested parties, to provide the Task Force with comments and recommendations.

The Task Force will then issue a final report containing our recommendations for improving the electric system and for any appropriate follow-up

Thank you Mr. Chairman. I will be happy to answer any questions you may have.

Summary of the major events that occurred
on August 14, 2003

- 12:15 - Eastern Daylight Time (EDT) - inaccurate input data rendered MISO's state estimator (a system monitoring tool) ineffective.

- 13:31 EDT - FE's Eastlake 5 generation unit tripped and shut down automatically.

- 14:14 EDT - the alarm and logging system in FE's control room failed and was not restored until after the blackout.

- 15:05 EDT - 3 of FE's 345-kV transmission lines began tripping out because the lines were contacting overgrown trees within the lines' right-of-way areas.

- 15:46 EDT - FE, MISO and neighboring utilities had begun to realize that the FE system was in jeopardy. The only way that the blackout might have been averted would have been to drop at least 1,500 to 2,500 MW of load around Cleveland and Akron -- and at this time the amount of load reduction required was increasing rapidly. No such effort was made.

- 15:46 EDT - the loss of key FE 345-kV lines in northern Ohio caused its underlying network of 138-kV lines to begin to fail, leading, in turn, to the loss of FE's Sammis-Star 345-kV line.

- 16:06 EDT - the Sammis-Star line tripped and triggered the cascade by shutting down the 345-kV path into northern Ohio from eastern Ohio. Although the area around Akron, Ohio was already blacked out due to earlier events, most of northern Ohio remained interconnected and electricity demand was high. The loss of the heavily overloaded Sammis-Star line instantly created major and unsustainable burdens on lines in adjacent areas, and the cascade spread rapidly as lines and generating units automatically took themselves out of service to avoid physical damage.

Hearing Before the United States Senate
Committee on Governmental Affairs
Subcommittee on Oversight of Government Management, the Federal Workforce, and the District of Columbia
November 20, 2003

Prepared Testimony of

Michehl R. Gent
President and Chief Executive Officer
North American Electric Reliability Council

Good morning, Mr. Chairman and members of the Committee. My name is Michehl Gent and I am President and Chief Executive Officer of the North American Electric Reliability Council (NERC). Thank you for inviting me to provide NERC's perspective on the interim report of the U.S.-Canada Power System Outage Task Force on the causes of the blackout on August 14, 2003.

NERC is a not-for-profit organization formed after the Northeast blackout in 1965 to promote the reliability of the bulk electric systems that serve North America. NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate, and secure. NERC works with all segments of the electric industry as well as electricity consumers and regulators to set and encourage compliance with rules for the planning and operation of reliable electric systems. NERC comprises ten Regional Reliability Councils that account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

NERC has been an integral part of the joint fact-finding investigation that led to the interim report on the August 14 blackout that the U.S.-Canada Power System Outage Task Force issued yesterday. NERC fully supports the findings and conclusions in the interim report. With respect to what happened on August 14, the key findings and conclusions are detailed on page 23 of the interim report, as follows: "inadequate situational awareness at First Energy Corporation," "First Energy failed to manage adequately tree growth in its transmission rights-of-way," and "failure of the interconnected grid's reliability organizations to provide effective diagnostic support."

Immediately after the onset of the blackout on August 14, 2003, NERC began assembling a team of the best technical experts in North America to investigate exactly what happened and why. Every human and data resource we have requested of the industry has been provided, and experts covering every aspect of the problem have been volunteered from across the United States and Canada. In the week following the blackout, NERC and representatives of DOE and the Federal Energy Regulatory Commission ("FERC") established a joint fact-finding investigation. All members of the team, regardless of their affiliation, have worked side by side to help correlate and understand the massive amounts of data that we have received. We have had hundreds of volunteers from organizations all across North America involved in the investigation so far.

To lead the NERC effort, we established a strong steering group of the industry's best, executive-level experts from systems not directly involved in the cascading grid failure. The steering group scope and members are described in Attachment A.

On October 15, NERC sent a letter to the CEOs of all reliability coordinators and control areas in North America directing them to verify within 60 days that their organizations are measuring up to reliability requirements in six key areas: Voltage and reactive management, reliability communications, failures of system monitoring and control functions, emergency action plans, training for emergencies, and vegetation management. The intent of this action was to minimize the likelihood of another blackout in the near future while the investigation is ongoing and a full set of recommendations is being developed. Responses are due on December 15. The full text of that letter is in Attachment B.

Chapter 6 of the interim report compares the August 14 blackout to other major disturbances on the interconnected bulk electric system. That comparison reveals that some of the causes of the August 14 blackout (inadequate vegetation management, failure to ensure operation within secure limits, failure to identify emergency conditions and communicate that status to neighboring systems, inadequate operator training, and inadequate regional-scale visibility over the power system) were repeats from the earlier outages, but it also revealed some causes not seen before (inadequate interregional visibility over the power system, dysfunction of a control area's SCADA/EMS system, and a lack of adequate backup to that system). The electricity industry has made great strides in responding to the recommendations from those earlier investigations, in the form of better communication capabilities, operator certification program, better tools for dealing with congestion on the grid, but clearly more needs to be done. For one thing, we are now using the bulk electric system harder than we have in the past and in ways for which it wasn't designed. Actions and practices that sufficed when the system had plenty of margin for error simply are inadequate when the system is being pushed more to its limits as electricity markets are increasingly characterized by larger transactions over greater distances. For another, the reliability responsibility for a given area that used to be concentrated within a single, vertically integrated organization is, in many parts of the country, now divided among several different entities.

One important step Congress can and should take to strengthen the reliability of the bulk power system in general would be to pass legislation to make the reliability rules mandatory and enforceable. For several years, NERC and a broad coalition of industry, government, and customer groups have been supporting legislation that would authorize creation of an industry-led self-regulatory organization, subject to oversight by FERC within the United States, to set and enforce reliability rules for the bulk electric system. NERC has developed a world-class set of planning and operating standards, though I expect we will find it necessary to improve those standards, based on the events of August 14. However, as long as compliance with these standards remains voluntary, we will fall short of providing the greatest possible assurance of reliability that could be achieved through mandatory verification of compliance and the ability to impose penalties and sanctions for non-compliance. On Tuesday, the House of Representatives passed H.R. 6, a comprehensive energy bill that includes the needed reliability legislation. H.R. 6 is now before the Senate for action.

As for the August 14 outage, much remains to be done. As the entity responsible for reliability standards for the bulk electric system, NERC must understand and communicate to its members what happened on August 14 and why it happened. The interim report is a major step in accomplishing that task. NERC must also determine whether any of its standards were violated and whether its standards and procedures require modifications to take into account the ways in which the bulk electric system is being used. Finally, NERC must assure that measures necessary to avoid a recurrence of the August 14 outage are taken.

NERC will continue to work with the U.S.-Canada Task Force as the investigation continues and recommendations are developed. We expect to learn many additional lessons from this event that will enable us to improve the overall reliability of the grid.

Thank you.

Attachment A

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

August 14, 2003 Blackout Investigation
NERC Steering Group

SCOPE
August 27, 2003

Scope

The NERC Steering Group steers the formulation and implementation of the NERC blackout investigation plan, reviews the milestone progress and results, and recommends improvements. The Steering Group provides a perspective of industry experts in power system planning, design, and operation.

Members

The members of the NERC Steering Group are:

Paul F. Barber, Facilitator
Barber Energy

W. Terry Boston
Executive Vice President
Transmission/Power Supply Group
Tennessee Valley Authority

Mark Fidrych
Power Operations Specialist
Western Area Power Administration

Sam R. Jones
Chief Operating Officer
Electric Reliability Council of Texas

Yakout Mansour
Senior Vice President
System Operations & Asset Management
British Columbia Transmission Corporation

William (Bill) K. Newman
Senior Vice President
Transmission Planning and Operations
Southern Company Services, Inc.

Terry M. Winter
President and Chief Executive Officer
California ISO

M. Dale McMaster
Executive Vice President–Operations and Reliability
Alberta Electric System Operator

Biographies

Paul F. Barber, Ph.D.
Barber Energy
Dr. Barber provides transmission and engineering services to the electric power industry in areas of governance, strategic planning, electric grid management, and power system reliability. He previously served as the Chair of the NERC Market Interface Committee and as the Vice Chair (Transmission Customers) of the Northeast Power Coordinating Council (NPCC). Dr. Barber joined Boston-based Citizens Power & Light, providing transmission and engineering technical expertise and support to all business lines of Citizens Power & Light and its successors. Dr. Barber served on the NERC Board of Trustees as well as the Boards of the Mid-Atlantic Area Council, Western Systems Coordinating Council (WSCC), and the three Regional Transmission Associations in the Western Interconnection. Prior to 1994, Dr. Barber served a 28-year career as an officer in the U.S. Army Corps of Engineers rising to the rank of Colonel. Dr. Barber received his BS degree from the U.S. Military Academy and MS degrees in electrical engineering and civil engineering from the University of Illinois. He completed a Ph.D. degree in electric power engineering from Rensselaer Polytechnic Institute in 1988. He has been registered in the State of Illinois as a professional engineer since 1974.

W. Terry Boston
Executive Vice President, Transmission/Power Supply Group
Tennessee Valley Authority
Terry Boston is Executive Vice President of the Tennessee Valley Authority's Transmission/Power Supply Group. Mr. Boston is the senior officer responsible for the planning, building, operation, and maintenance of TVA's transmission and power supply network. He joined TVA as a power supply engineer in 1972, and was named head of the Power Supply Group in 1980. Over the next 16 years, he directed three TVA divisions in succession: Transmission, Regional Operations, and Electric System Reliability. Mr. Boston has served for six years on the NERC Engineering Committee and Transmission Task Force, and is on the NERC Stakeholders Committee. He is vice president of CIGRE, the International Council on Large Electric Systems, and vice president of CERTS (the Consortium for Electric Reliability Technology Solutions). Boston holds a B.S. in engineering from Tennessee Technological University and an M.S. in engineering administration from the University of Tennessee.

Mark Fidrych
Power Operations Specialist
Western Area Power Administration
Mark E. Fidrych has served as the Manager of Western Area Power Administration's Rocky Mountain Desert Southwest Reliability Center. Mr. Fidrych began his career with WAPA in 1979, working in maintenance and marketing, with the majority of his career having been in power system operations. He directed activities in the computer systems and power scheduling divisions before becoming the Operations Manager in 1990. A 1972 graduate of the University of Rhode Island, Mr. Fidrych received a bachelor's degree in electrical engineering. In 1980, he received a master's degree in public administration from the University of Colorado. Mr. Fidrych is the present Chair of the NERC Operating Committee. He has also served as the Chair of the NERC Security Coordinator and the Operating Reliability Subcommittees.

Sam R. Jones
Chief Operating Officer
Electric Reliability Council of Texas
Sam R. Jones became the first Director of the Electric Reliability Council of Texas (ERCOT) on December 1, 1996. In March 2000, he was appointed as the Executive Vice President and Chief Operating Officer of ERCOT. Prior to joining ERCOT, Mr. Jones was employed by the City of Austin, Texas, Electric Utility for over 35 years. With the City of Austin, he held engineering and management positions in the areas of distribution, transmission, substation, generation and system operations. He was responsible for the development of Austin's first energy control center. He retired from the City of Austin as Director of Generation and Energy Control. He has been active in inter-utility reliability work for over 19 years. He is a two-time past chair of the ERCOT Operating Subcommittee, and a current Vice-Chair of the NERC Operating Committee, and a past chair (or member) of numerous NERC and ERCOT subcommittees and task forces. Mr. Jones has a degree in Electrical Engineering from the University of Texas at Austin and is a Registered Professional Engineer in Texas.

Yakout Mansour
Senior Vice President, System Operations & Asset Management
British Columbia Transmission Corporation
Yakout Mansour is Senior Vice President of System Operations & Asset Management of the British Columbia Transmission Corporation. Previously, he served as the Vice President of the Grid Operations and Inter-Utility Affairs division of BC Hydro, responsible for BC Hydro's transmission, distribution and generation dispatch operations as well as the development of policies and practices related to inter-utility transmission access. Mr. Mansour currently serves as BC Hydro's principal representative and board member on the RTO West filing utilities structure and has been the Canadian representative in the RTO consultation process. Mr. Mansour is a registered Professional Engineer in the Provinces of British Columbia and Alberta with over 30 years experience in power system planning, system and market operation, design and research. He is a Fellow of IEEE, has authored and co-authored over 100 papers and special publications of IEEE and other international professional institutions, has provided training and consulting services around the world, and holds U.S. and Canadian patents.

Dale McMaster, P.Eng.
Executive Vice-President, Operations and Reliability
Alberta Electric System Operator (AESO)
Dale McMaster is Executive Vice-President, Operations and Reliability for the Alberta Electric System Operator (AESO). The AESO integrates the functions of the Power Pool of Alberta, the Transmission Administrator of Alberta, and provincial load settlement. Mr. McMaster's knowledge of system planning and his overall industry experience integrates the AESO's operational and planning areas. As President and System Controller, Mr. McMaster played a key role during the integration of the former Power Pool and the Transmission Administration. Mr. McMaster joined the former Power Pool of Alberta in 1996 as Chief Operations Officer, with responsibility for the system control function, the ongoing development of the Alberta electric energy market, and strategic planning. He is an electrical engineer with more than 25 years of experience in power systems in Canada and abroad. Mr. McMaster received his degree in electrical engineering from the University of Saskatchewan and held a variety of senior management positions at SaskPower, SNC-Lavalin, and Acres International. He is a member of the Association of Professional Engineers, and the Canadian Electricity Association.

William K. Newman
Senior Vice President, Transmission Planning & Operations
Southern Company
William K. Newman began his career with Georgia Power Company in 1966 and progressed through positions of increasing responsibility at Georgia Power for 18 years. In 1984, he assumed the position of General Manager, Power Operations, at Mississippi Power Company, was promoted to Director of Power Delivery in 1988 and named Vice President, Power Generation and Delivery, in 1989. His responsibilities at Mississippi Power Company included the areas of fuels, environmental, generating plants, transmission, and system operations. He transferred to Southern Company Services in 1992 as Vice President, Operating and Planning Services and was named Senior Vice President, Transmission Planning and Operations in 1995. He is responsible for planning and operation of the Southern electric system's network transmission grid in order to provide economic, reliable service to all users. Mr. Newman has served in numerous academic and professional organizations and is currently Chairman, Southeastern Electric Reliability Council. He is a Registered Professional Engineer in the states of Georgia and Mississippi.

Terry M. Winter,
President and Chief Executive Officer
California ISO
Terry M. Winter is President and Chief Executive Officer of the California Independent System Operator (ISO), a position he has held since March 1, 1999. Mr. Winter was formerly Chief Operating Officer of the California ISO, having accepted the position in August 1997. He assisted in developing operations from the ground up and oversaw the integration of the transmission systems of Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric when the California ISO assumed control of the state's open market transmission grid on March 31, 1998. Mr. Winter was formerly the Division Manager of San Diego Gas & Electric's power operations. His 21-year career with SDG&E focused on power operations, transmission engineering and project management. Prior to his tenure with SDG&E he worked on electrical transmission and distribution engineering for Arizona's Salt River Project for 10 years. Mr. Winter holds professional engineering licenses in both California and Arizona. Mr. Winter graduated from the University of Idaho with a Bachelor of Science degree in Electrical Engineering.

Attachment B

MICHEHL R. GENT
President and CEO

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

October 15, 2003

Name
Address

Dear Name:

Near-Term Actions to Assure Reliable Operations

On October 10, 2003, the NERC Board of Trustees, with the endorsement of its Stakeholders Committee, directed that the following letter be sent to the CEOs of all NERC control areas and reliability coordinators.

NERC is assisting the U.S.-Canada Joint Task Force's investigation of the August 14, 2003, blackout that affected parts of the Midwest and Northeast United States, and Ontario, Canada. Although considerable progress has been made in the investigation to determine what happened, an understanding of the causes of the outage is still being developed through analysis by teams of experts.

The reliability of the North American bulk electric systems, including the avoidance of future cascading outages, is of paramount importance to NERC and its stakeholders. Pending the outcome of the final report on the outage, NERC emphasizes to all entities responsible for the reliable operation of bulk electric systems the importance of assuring those systems are operated within their design criteria and within conditions known to be reliable through analytic study. If the power system enters an unanalyzed state, system operators must have the authority and the capability to take emergency actions to return the power system to a safe condition.

NERC requests that each entity in North America that operates a control area and each NERC reliability coordinator review the following list of reliability practices to ensure their organizations are within NERC and regional reliability council standards and established good utility practices. NERC further requests that within 60 days, each entity report in writing to their respective regional reliability council, with a copy to NERC, that such a review has been completed and the status of any necessary corrective actions. This brief list of near-term actions is not in any way intended to diminish the need to comply with all NERC and regional reliability council standards and good utility practices.

1. **Voltage and Reactive Management:** Ensure sufficient voltage support for reliable operations.

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- Establish a daily voltage/reactive management plan, assuring an adequate static and dynamic reactive supply under a credible range of system dispatch patterns.
- During anticipated heavy load days, or conditions of system stress such as caused by heavy wide-area transfers, ensure all possible VAR supplies are verified and available, and VAR supplies are applied early in the day ahead of load pickup.
- Reserve sufficient dynamic reactive supply (e.g. online generation and other dynamic VAR resources) to meet regional operating criteria and system needs.
- In accordance with NERC and regional practices maintain voltage schedules of all bulk electric transmission facilities above 95% of nominal values <u>and</u> in conformance with regional criteria.
- Report any low voltage limit violations at critical high voltage transmission facilities to the reliability coordinator.
- Ensure all interconnected generators that have, or are required to have, automatic voltage regulation (AVR) are operating under AVR.
- Coordinate potential differences of voltage criteria and schedules between systems and ensure these differences are factored into daily operations.

2. **Reliability Communications:** Review, and as necessary strengthen, communication protocols between control area operators, reliability coordinators, and ISOs.
   - Share the status of key facilities with other appropriate control area operators, reliability coordinators, and ISOs.
   - Control area operators, reliability coordinators, and ISOs should conduct periodic conference calls to discuss expected system conditions and notify all neighboring systems of any unusual conditions. Conduct additional calls as needed for system critical days.

3. **Failures of System Monitoring and Control Functions:** Review and as necessary, establish a formal means to immediately notify control room personnel when SCADA or EMS functions, that are critical to reliability, have failed and when they are restored.
   - Establish an automated method to alert power system operators and technical support personnel when power system status indications are not current, or that alarms are not being received or annunciated.
   - Determine what backup capabilities can be utilized when primary alarm systems are unavailable. If a backup to failed alarms is not immediately available, then monitoring and control should be transferred in accordance with approved backup plans.
   - Identify and implement procedures to move to 'conservative system operations' when operators are unsure about next contingency outcomes (i.e., unstudied conditions, loss of SCADA or EMS visibility, unexplained or unknown power system conditions).
   - Ensure all critical computer and communication systems have a backup power supply, and the backup supply is periodically tested.
   - Ensure that system operators have a clear understanding of the impact to their energy management system control functions whenever their transaction tagging and scheduling systems fail. Identify and implement appropriate contingency procedures for loss of real-time ACE and AGC control.

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4. **Emergency Action Plans:** Ensure that emergency action plans and procedures are in place to safeguard the system under emergency conditions by defining actions operators may take to arrest disturbances and prevent cascading.
   - Actions might include but should not be limited to acting immediately to reduce transmission loading, ordering redispatch, requiring maximum reactive output from interconnected resources, and shedding load without first implementing normal operating procedures.
   - Ensure operators know, not only that they have the authority to shed load under emergencies, but that, in addition, they are expected to exercise that authority to prevent cascading.

5. **Training for Emergencies:** Ensure that all operating staff are trained and certified, if required, and practice emergency drills that include criteria for declaring an emergency, prioritized action plans, staffing and responsibilities, and communications.

6. **Vegetation Management:** Ensure high voltage transmission line rights of way are free of vegetation and other obstructions that could contact an energized conductor within the normal and emergency ratings of each line.

Sincerely,

U.S.-Canada Power System Outage Task Force

Interim Report:

Causes of the August 14th Blackout in the United States and Canada

Canada

November 2003

Acknowledgments

The U.S.-Canada Power System Outage Task Force would like to acknowledge all the researchers, analysts, modelers, investigators, planners, designers, and others for their time and effort spent on completing this Interim Report. The result is an international coordinated report providing factual reasons as to why the power outage occurred. This Interim Report was prepared for the U.S. Secretary of Energy and the Minister of Natural Resources Canada (NRCAN) under the direction of Jimmy Glotfelty (USDOE) and Dr. Nawal Kamel and the three working groups: electric system, nuclear, and security.

Members of the three working groups and investigative teams spent an incalculable number of hours researching in various locations to better understand the intricacies of the August 14, 2003, power outage. It was a huge endeavor to achieve, and they did an excellent job providing the facts though a variety of data requests; analysis of operations, generator and transmission modeling; sequence of events, and root cause analysis. Along with countless interviews and a variety of side investigations, the planning and preparation, coordinated internationally, all proved to be a confidently coordinated effort.

Thank you for spending countless hours on in-depth research and participating in a report that will help the North American public and the world better understand why and what caused the August 14, 2003, blackout. Your efforts are greatly appreciated! Thank you.

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1. Introduction

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, and New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and power was not restored for 2 days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored.

On August 15, President George W. Bush and Prime Minister Jean Chrétien directed that a joint U.S.-Canada Power System Outage Task Force be established to investigate the causes of the blackout and how to reduce the possibility of future outages. They named U.S. Secretary of Energy Spencer Abraham and Herb Dhaliwal, Minister of Natural Resources, Canada, to chair the joint Task Force. Three other U.S. representatives and three other Canadian representatives were named to the Task Force. The U.S. members are Tom Ridge, Secretary of Homeland Security; Pat Wood, Chairman of the Federal Energy Regulatory Commission; and Nils Diaz, Chairman of the Nuclear Regulatory Commission. The Canadian members are Deputy Prime Minister John Manley, Deputy Prime Minister; Kenneth Vollman, Chairman of the National Energy Board; and Linda J. Keen, President and CEO of the Canadian Nuclear Safety Commission.

The Task Force divided its work into two phases:

- Phase I: Investigate the outage to determine its causes and why it was not contained.
- Phase II: Develop recommendations to reduce the possibility of future outages and minimize the scope of any that occur.

The Task Force created three Working Groups to assist in the Phase I investigation of the blackout—an Electric System Working Group (ESWG), a Nuclear Working Group (NWG), and a Security Working Group (SWG). They were tasked with overseeing and reviewing investigations of the conditions and events in their respective areas and determining whether they may have caused or affected the blackout. The Working Groups are made up of State and provincial representatives, Federal employees, and contractors working for the U.S. and Canadian government agencies represented on the Task Force.

This document provides an Interim Report, forwarded by the Working Groups, on the findings of the Phase I investigation. It presents the facts that the bi-national investigation has found regarding the causes of the blackout on August 14, 2003. The Working Groups and their analytic teams are confident of the accuracy of these facts and the analysis built upon them. This report does not offer speculations or assumptions not supported by evidence and analysis. Further, it does not attempt to draw broad conclusions or suggest policy recommendations; that task is to be undertaken in Phase II and is beyond the scope of the Phase I investigation.

This report will now be subject to public review and comment. The Working Groups will consider public commentary on the Interim Report and will oversee and review any additional analyses and investigation that may be required. This report will be finalized and made a part of the Task Force Final Report, which will also contain recommendations on how to minimize the likelihood and scope of future blackouts.

The Task Force will hold three public forums, or consultations, in which the public will have the opportunity to comment on this Interim Report and to present recommendations for consideration by the Working Groups and the Task Force.

The public may also submit comments and recommendations to the Task Force electronically or by mail. Electronic submissions may be sent to:

poweroutage@nrcan.gc.ca
and
blackout.report@hq.doe.gov.

Paper submissions may be sent by mail to:

Dr. Nawal Kamel
Special Adviser to the Deputy Minister
Natural Resources Canada
21st Floor
580 Booth Street
Ottawa, ON K1A 0E4
and
Mr. James W. Glotfelty
Director, Office of Electric Transmission and Distribution
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585

This Interim Report is divided into eight chapters, including this introductory chapter:

- Chapter 2 provides an overview of the institutional framework for maintaining and ensuring the reliability of the bulk power system in North America, with particular attention to the roles and responsibilities of several types of reliability-related organizations.
- Chapter 3 discusses conditions on the regional power system before August 14 and on August 14 before the events directly related to the blackout began.
- Chapter 4 addresses the causes of the blackout, with particular attention to the evolution of conditions on the afternoon of August 14, starting from normal operating conditions, then going into a period of abnormal but still potentially manageable conditions, and finally into an uncontrollable cascading blackout.
- Chapter 5 provides details on the cascade phase of the blackout.
- Chapter 6 compares the August 14, 2003, blackout with previous major North American power outages.
- Chapter 7 examines the performance of the nuclear power plants affected by the August 14 outage.
- Chapter 8 addresses issues related to physical and cyber security associated with the outage.

This report also includes four appendixes: a description of the investigative process that provided the basis for this report, a list of electricity acronyms, a glossary of electricity terms, and three transmittal letters pertinent to this report from the three Working Groups.

2. Overview of the North American Electric Power System and Its Reliability Organizations

The North American Power Grid Is One Large, Interconnected Machine

The North American electricity system is one of the great engineering achievements of the past 100 years. This electricity infrastructure represents more than $1 trillion in asset value, more than 200,000 miles (320,000 kilometers) of transmission lines operating at 230,000 volts and greater, 950,000 megawatts of generating capability, and nearly 3,500 utility organizations serving well over 100 million customers and 283 million people.

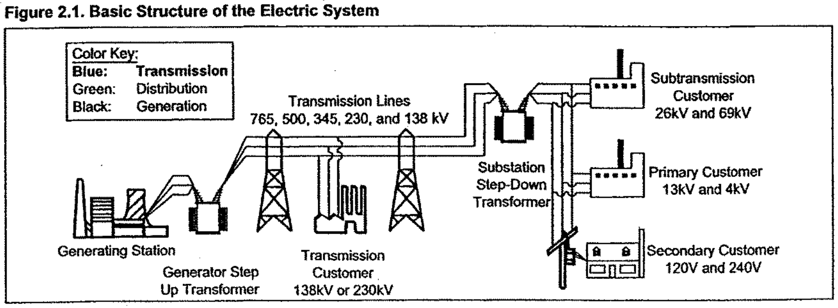
Modern society has come to depend on reliable electricity as an essential resource for national security; health and welfare; communications; finance; transportation; food and water supply; heating, cooling, and lighting; computers and electronics; commercial enterprise; and even entertainment and leisure—in short, nearly all aspects of modern life. Customers have grown to expect that electricity will almost always be available when needed at the flick of a switch. Most customers have also experienced local outages caused by a car hitting a power pole, a construction crew accidentally damaging a cable, or a lightning storm. What is not expected is the occurrence of a massive outage on a calm, warm day. Widespread electrical outages, such as the one that occurred on August 14, 2003, are rare, but they can happen if multiple reliability safeguards break down.

Providing reliable electricity is an enormously complex technical challenge, even on the most routine of days. It involves real-time assessment, control and coordination of electricity production at thousands of generators, moving electricity across an interconnected network of transmission lines, and ultimately delivering the electricity to millions of customers by means of a distribution network.

As shown in Figure 2.1, electricity is produced at lower voltages (10,000 to 25,000 volts) at generators from various fuel sources, such as nuclear, coal, oil, natural gas, hydro power, geothermal, photovoltaic, etc. Some generators are owned by the same electric utilities that serve the end-use customer; some are owned by independent power producers (IPPs); and others are owned by customers themselves—particularly large industrial customers.

Electricity from generators is "stepped up" to higher voltages for transportation in bulk over

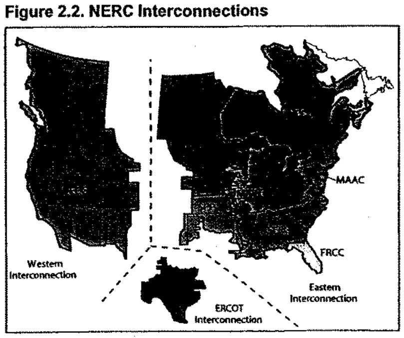
Figure 2.1. Basic Structure of the Electric System



transmission lines. Operating the transmission lines at high voltage (i.e., 230,000 to 765,000 volts) reduces the losses of electricity from conductor heating and allows power to be shipped economically over long distances. Transmission lines are interconnected at switching stations and substations to form a network of lines and stations called the power "grid." Electricity flows through the interconnected network of transmission lines from the generators to the loads in accordance with the laws of physics—along "paths of least resistance," in much the same way that water flows through a network of canals. When the power arrives near a load center, it is "stepped down" to lower voltages for distribution to customers. The bulk power system is predominantly an alternating current (AC) system, as opposed to a direct current (DC) system, because of the ease and low cost with which voltages in AC systems can be converted from one level to another. Some larger industrial and commercial customers take service at intermediate voltage levels (12,000 to 115,000 volts), but most residential customers take their electrical service at 120 and 240 volts.

While the power system in North America is commonly referred to as "the grid," there are actually three distinct power grids or "interconnections" (Figure 2.2). The Eastern Interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces. The Western Interconnection includes the western third of the continental United States (excluding Alaska), the Canadian Provinces of Alberta and British Columbia, and a portion of Baja California Norte, Mexico. The third interconnection comprises most of the state of Texas. The three interconnections are electrically independent from each other except for a few small direct current (DC) ties that link them. Within each interconnection, electricity is produced the instant it is used, and flows over virtually all transmission lines from generators to loads.

Figure 2.2. NERC Interconnections



The northeastern portion of the Eastern Interconnection (about 10 percent of the interconnection's total load) was affected by the August 14 blackout. The other two interconnections were not affected.[1]

Planning and Reliable Operation of the Power Grid Are Technically Demanding

Reliable operation of the power grid is complex and demanding for two fundamental reasons:

- First, electricity flows at the speed of light (186,000 miles per second or 297,600 kilometers per second) and is not economically storable in large quantities. Therefore electricity must be produced the instant it is used.
- Second, the flow of alternating current (AC) electricity cannot be controlled like a liquid or gas by opening or closing a valve in a pipe, or switched like calls over a long-distance telephone network. Electricity flows freely along all available paths from the generators to the loads in accordance with the laws of physics—dividing among all connected flow paths in the network, in inverse proportion to the impedance (resistance plus reactance) on each path.

Maintaining reliability is a complex enterprise that requires trained and skilled operators, sophisticated computers and communications, and careful planning and design. The North American Electric Reliability Council (NERC) and its ten Regional Reliability Councils have developed system operating and planning standards for ensuring the reliability of a transmission grid that are based on seven key concepts:

- Balance power generation and demand continuously.
- Balance reactive power supply and demand to maintain scheduled voltages.
- Monitor flows over transmission lines and other facilities to ensure that thermal (heating) limits are not exceeded.

- ◆ Keep the system in a stable condition.
- ◆ Operate the system so that it remains in a reliable condition even if a contingency occurs, such as the loss of a key generator or transmission facility (the "N-1 criterion").
- ◆ Plan, design, and maintain the system to operate reliably.
- ◆ Prepare for emergencies.

These seven concepts are explained in more detail below.

1. **Balance power generation and demand continuously.** To enable customers to use as much electricity as they wish at any moment, production by the generators must be scheduled or "dispatched" to meet constantly changing demands, typically on an hourly basis, and then fine-tuned throughout the hour, sometimes through the use of automatic generation controls to continuously match generation to actual demand. Demand is somewhat predictable, appearing as a daily demand curve—in the summer, highest during the afternoon and evening and lowest in the middle of the night, and higher on weekdays when most businesses are open (Figure 2.3).

   Failure to match generation to demand causes the frequency of an AC power system (nominally 60 cycles per second or 60 Hertz) to increase (when generation exceeds demand) or decrease (when generation is less than demand) (Figure 2.4). Random, small variations in frequency are normal, as loads come on and off and generators modify their output to follow the demand changes. However, large deviations in frequency can cause the rotational speed of generators to fluctuate, leading to vibrations that can damage generator turbine blades and other equipment. Extreme low frequencies can trigger automatic under-frequency "load shedding," which takes blocks of customers off-line in order to prevent a total collapse of the electric system. As will be seen later in this report, such an imbalance of generation and demand can also occur when the system responds to major disturbances by breaking into separate "islands"; any such island may have an excess or a shortage of generation, compared to demand within the island.

2. **Balance reactive power supply and demand to maintain scheduled voltages.** Reactive power sources, such as capacitor banks and generators, must be adjusted during the day to maintain voltages within a secure range pertaining to all system electrical equipment (stations, transmission lines, and customer equipment). Most generators have automatic voltage regulators that cause the reactive power output of generators to increase or decrease to control voltages to scheduled levels. Low voltage can cause electric system instability or collapse and, at distribution voltages, can cause damage to motors and the failure of electronic equipment. High voltages can exceed the insulation capabilities of equipment and cause dangerous electric arcs ("flashovers").

3. **Monitor flows over transmission lines and other facilities to ensure that thermal (heating) limits are not exceeded.** The dynamic interactions between generators and loads, combined with the fact that electricity flows freely across all interconnected circuits, mean that power flow is ever-changing on transmission and distribution lines. All lines, transformers, and other equipment carrying electricity are heated by the flow of electricity through them. The

Figure 2.3. PJM Load Curve, August 18-24, 2003

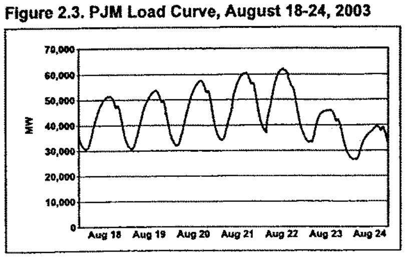
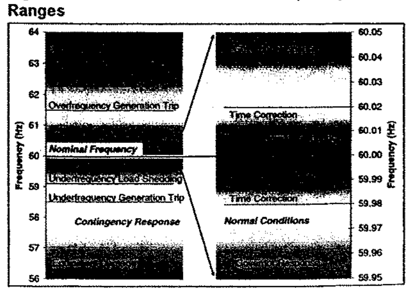


Figure 2.4. Normal and Abnormal Frequency Ranges



Local Supplies of Reactive Power Are Essential to Maintaining Voltage Stability

A generator typically produces some mixture of "active" and "reactive" power, and the balance between them can be adjusted at short notice to meet changing conditions. Active power, measured in watts, is the form of electricity that powers equipment. Reactive power, a characteristic of AC systems, is measured in volt-amperes reactive (VAr), and is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps, and air conditioning.) Transmission lines both consume and produce reactive power. At light loads they are net producers, and at heavy loads, they are heavy consumers. Reactive power consumption by these facilities or devices tends to depress transmission voltage, while its production (by generators) or injection (from storage devices such as capacitors) tends to support voltage. Reactive power can be transmitted only over relatively short distances, and thus must be supplied as needed from nearby generators or capacitor banks. If reactive power cannot be supplied promptly and in sufficient quantity, voltages decay, and in extreme cases a "voltage collapse" may result.

flow must be limited to avoid overheating and damaging the equipment. In the case of overhead power lines, heating also causes the metal conductor to stretch or expand and sag closer to ground level. Conductor heating is also affected by ambient temperature, wind, and other factors. Flow on overhead lines must be limited to ensure that the line does not sag into obstructions below such as trees or telephone lines, or violate the minimum safety clearances between the energized lines and other objects. (A short circuit or "flashover"—which can start fires or damage equipment—can occur if an energized line gets too close to another object). All electric lines, transformers and other current-carrying devices are monitored continuously to ensure that they do not become overloaded or violate other operating constraints. Multiple ratings are typically used, one for normal conditions and a higher rating for emergencies. The primary means of limiting the flow of power on transmission lines is to adjust selectively the output of generators.

4. **Keep the system in a stable condition.** Because the electric system is interconnected and dynamic, electrical stability limits must be observed. Stability problems can develop very quickly—in just a few cycles (a cycle is 1/60th of a second)—or more slowly, over seconds or minutes. The main concern is to ensure that generation dispatch and the resulting power flows and voltages are such that the system is stable at all times. (As will be described later in this report, part of the Eastern Interconnection became unstable on August 14, resulting in a cascading outage over a wide area.) Stability limits, like thermal limits, are expressed as a maximum amount of electricity that can be safely transferred over transmission lines.

   There are two types of stability limits: (1) Voltage stability limits are set to ensure that the unplanned loss of a line or generator (which may have been providing locally critical reactive power support, as described previously) will not cause voltages to fall to dangerously low levels. If voltage falls too low, it begins to collapse uncontrollably, at which point automatic relays either shed load or trip generators to avoid damage. (2) Power (angle) stability limits are set to ensure that a short circuit or an unplanned loss of a line, transformer, or generator will not cause the remaining generators and loads being served to lose synchronism with one another. (Recall that all generators and loads within an interconnection must operate at or very near a common 60 Hz frequency.) Loss of synchronism with the common frequency means generators are operating out-of-step with one another. Even modest losses of synchronism can result in damage to generation equipment. Under extreme losses of synchronism, the grid may break apart into separate electrical islands; each island would begin to maintain its own frequency, determined by the load/generation balance within the island.

5. **Operate the system so that it remains in a reliable condition even if a contingency occurs, such as the loss of a key generator or transmission facility (the "N minus 1 criterion").** The central organizing principle of electricity reliability management is to plan for the unexpected. The unique features of electricity mean

that problems, when they arise, can spread and escalate very quickly if proper safeguards are not in place. Accordingly, through years of experience, the industry has developed a sequence of defensive strategies for maintaining reliability based on the assumption that equipment can and will fail unexpectedly upon occasion.

This principle is expressed by the requirement that the system must be operated at all times to ensure that it will remain in a secure condition (generally within emergency ratings for current and voltage and within established stability limits) following the loss of the most important generator or transmission facility (a "worst single contingency"). This is called the "N-1 criterion." In other words, because a generator or line trip can occur at any time from random failure, the power system must be operated in a preventive mode so that the loss of the most important generator or transmission facility does not jeopardize the remaining facilities in the system by causing them to exceed their emergency ratings or stability limits, which could lead to a cascading outage.

Further, when a contingency does occur, the operators are required to identify and assess immediately the new worst contingencies, given the changed conditions, and promptly make any adjustments needed to ensure that if one of them were to occur, the system would still remain operational and safe. NERC operating policy requires that the system be restored as soon as practical but within no more than 30 minutes to compliance with normal limits, and to a condition where it can once again withstand the next-worst single contingency without violating thermal, voltage, or stability limits. A few areas of the grid are operated to withstand the concurrent loss of two or more facilities (i.e., "N-2"). This may be done, for example, as an added safety measure to protect a densely populated metropolitan area or when lines share a common structure and could be affected by a common failure mode, e.g., a single lightning strike.

6. **Plan, design, and maintain the system to operate reliably.** Reliable power system operation requires far more than monitoring and controlling the system in real-time. Thorough planning, design, maintenance, and analysis are required to ensure that the system can be operated reliably and within safe limits. Short-term planning addresses day-ahead and week-ahead operations planning; long-term planning focuses on providing adequate generation resources and transmission capacity to ensure that in the future the system will be able to withstand severe contingencies without experiencing widespread, uncontrolled cascading outages.

   A utility that serves retail customers must estimate future loads and, in some cases, arrange for adequate sources of supplies and plan adequate transmission and distribution infrastructure. NERC planning standards identify a range of possible contingencies and set corresponding expectations for system performance under several categories of possible events. Three categories represent the more probable types of events that the system must be planned to withstand. A fourth category represents "extreme events" that may involve substantial loss of customer load and generation in a widespread area. NERC planning standards also address requirements for voltage support and reactive power, disturbance monitoring, facility ratings, system modeling and data requirements, system protection and control, and system restoration.

7. **Prepare for emergencies.** System operators are required to take the steps described above to plan and operate a reliable power system, but emergencies can still occur because of external factors such as severe weather, operator error, or equipment failures that exceed planning, design, or operating criteria. For these rare events, the operating entity is required to have emergency procedures covering a credible range of emergency scenarios. Operators must be trained to recognize and take effective action in response to these emergencies. To deal with a system emergency that results in a blackout, such as the one that occurred on August 14, 2003, there must be procedures and capabilities to use "black start" generators (capable of restarting with no external power source) and to coordinate operations in order to restore the system as quickly as possible to a normal and reliable condition.

Reliability Organizations Oversee Grid Reliability in North America

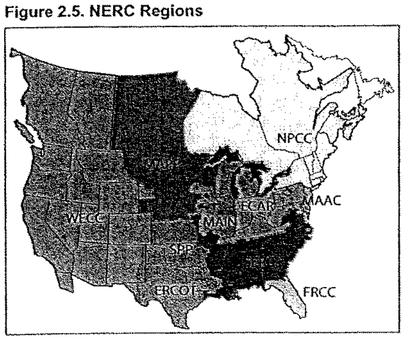
NERC is a non-governmental entity whose mission is to ensure that the bulk electric system in North America is reliable, adequate and secure.

The organization was established in 1968, as a result of the Northeast blackout in 1965. Since its inception, NERC has operated as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of all those involved to ensure compliance with reliability requirements. An independent board governs NERC.

To fulfill its mission, NERC:

- ◆ Sets standards for the reliable operation and planning of the bulk electric system.
- ◆ Monitors and assesses compliance with standards for bulk electric system reliability.
- ◆ Provides education and training resources to promote bulk electric system reliability.
- ◆ Assesses, analyzes and reports on bulk electric system adequacy and performance.
- ◆ Coordinates with Regional Reliability Councils and other organizations.
- ◆ Coordinates the provision of applications (tools), data and services necessary to support the reliable operation and planning of the bulk electric system.
- ◆ Certifies reliability service organizations and personnel.
- ◆ Coordinates critical infrastructure protection of the bulk electric system.
- ◆ Enables the reliable operation of the interconnected bulk electric system by facilitating information exchange and coordination among reliability service organizations.

Figure 2.5. NERC Regions



Recent changes in the electricity industry have altered many of the traditional mechanisms, incentives and responsibilities of the entities involved in ensuring reliability, to the point that the voluntary system of compliance with reliability standards is generally recognized as not adequate to current needs.[2] NERC and many other electricity organizations support the development of a new mandatory system of reliability standards and compliance, backstopped in the United States by the Federal Energy Regulatory Commission. This will require federal legislation in the United States to provide for the creation of a new electric reliability organization with the statutory authority to enforce compliance with reliability standards among all market participants. Appropriate government entities in Canada and Mexico are prepared to take similar action, and some have already done so. In the meantime, NERC encourages compliance with its reliability standards through an agreement with its members.

NERC's members are ten Regional Reliability Councils. (See Figure 2.5 for a map showing the locations and boundaries of the regional councils.) The regional councils and NERC have opened their membership to include all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. Collectively, the members of the NERC regions account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The ten regional councils jointly fund NERC and adapt NERC standards to meet the needs of their regions. The August 14 blackout affected three NERC regional reliability councils—East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Northeast Power Coordinating Council (NPCC).

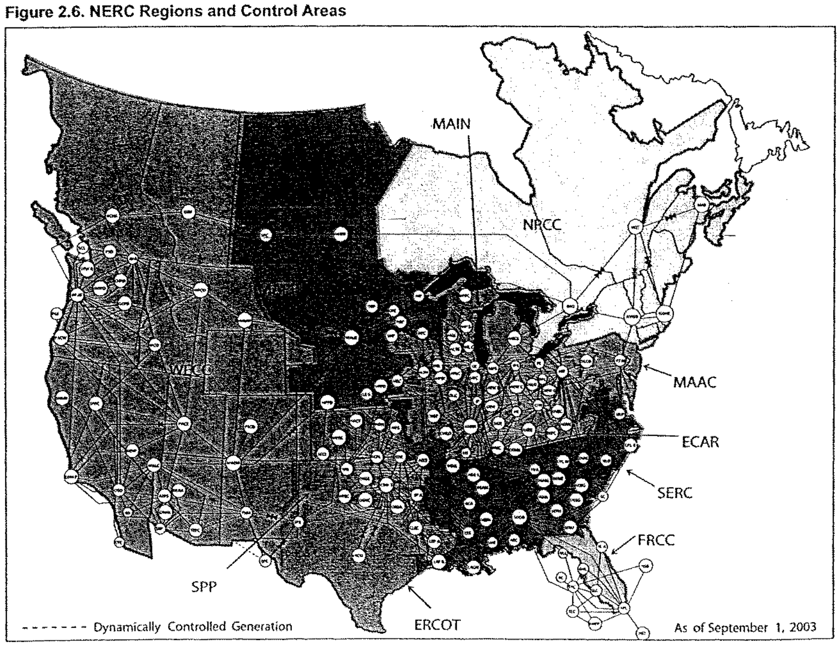
"Control areas" are the primary operational entities that are subject to NERC and regional council standards for reliability. A control area is a geographic area within which a single entity, Independent System Operator (ISO), or Regional Transmission Organization (RTO) balances generation and loads in real time to maintain reliable operation. Control areas are linked with each other through transmission interconnection tie lines. Control area operators control generation directly to maintain their electricity interchange schedules with other control areas. They also operate collectively to support the reliability of their interconnection. As shown in Figure 2.6, there are approximately 140 control areas in North America. The control area dispatch centers have sophisticated monitoring and control systems and are staffed 24 hours per day, 365 days per year.

Traditionally, control areas were defined by utility service area boundaries and operations were largely managed by vertically integrated utilities that owned and operated generation, transmission, and distribution. While that is still true in some areas, there has been significant restructuring of operating functions and some consolidation of control areas into regional operating entities. Utility industry restructuring has led to an unbundling of generation, transmission and distribution activities such that the ownership and operation of these assets have been separated either functionally or through the formation of independent entities called Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

- ISOs and RTOs in the United States have been authorized by FERC to implement aspects of the Energy Policy Act of 1992 and subsequent FERC policy directives.
- The primary functions of ISOs and RTOs are to manage in real time and on a day-ahead basis the reliability of the bulk power system and the operation of wholesale electricity markets within their footprint.
- ISOs and RTOs do not own transmission assets; they operate or direct the operation of assets owned by their members.
- ISOs and RTOs may be control areas themselves, or they may encompass more than one control area.
- ISOs and RTOs may also be NERC Reliability Coordinators, as described below.

Five RTOs/ISOs are within the area directly affected by the August 14 blackout. They are:

Figure 2.6. NERC Regions and Control Areas



- Midwest Independent System Operator (MISO)
- PJM Interconnection (PJM)
- New York Independent System Operator (NYISO)
- New England Independent System Operator (ISO-NE)
- Ontario Independent Market Operator (IMO)

Reliability coordinators provide reliability oversight over a wide region. They prepare reliability assessments, provide a wide-area view of reliability, and coordinate emergency operations in real time for one or more control areas. They do not participate in the wholesale or retail market functions. There are currently 18 reliability coordinators in North America. Figure 2.7 shows the locations and boundaries of their respective areas.

Key Parties in the Pre-Cascade Phase of the August 14 Blackout

The initiating events of the blackout involved two control areas—FirstEnergy (FE) and American Electric Power (AEP)—and their respective reliability coordinators, MISO and PJM (see Figures 2.7 and 2.8). These organizations and their reliability responsibilities are described briefly in this final subsection.

1. **FirstEnergy operates a control area in northern Ohio.** FirstEnergy (FE) consists of seven electric utility operating companies. Four of these companies, Ohio Edison, Toledo Edison, The Illuminating Company, and Penn Power, operate in the NERC ECAR region, with MISO serving as their reliability coordinator. These four companies now operate as one integrated control area managed by FE.[3]

2. **American Electric Power (AEP) operates a control area in Ohio just south of FE.** AEP is both a transmission operator and a control area operator.

3. **Midwest Independent System Operator (MISO) is the reliability coordinator for FirstEnergy.** The Midwest Independent System Operator (MISO) is the reliability coordinator for a region of more than one million square miles, stretching from Manitoba, Canada in the north to Kentucky in the south, from Montana in the west to western Pennsylvania in the east. Reliability coordination is provided by two offices, one in Minnesota, and the other at the MISO headquarters in Indiana. Overall, MISO provides reliability coordination for 37 control areas, most of which are members of MISO.

4. **PJM is AEP's reliability coordinator.** PJM is one of the original ISOs formed after FERC orders 888 and 889, but was established as a regional power pool in 1935. PJM recently expanded its footprint to include control areas and transmission operators within MAIN and ECAR (PJM-West). It performs its duties as a reliability coordinator in different ways, depending on the control areas involved. For PJM-East, it is both the control area and reliability coordinator for ten utilities, whose transmission systems span the Mid-Atlantic region of New Jersey, most of Pennsylvania, Delaware, Maryland, West Virginia, Ohio, Virginia, and the District of Columbia. The PJM-West facility has the reliability coordinator desk for five control areas (AEP, Commonwealth Edison, Duquesne Light,

Figure 2.7. NERC Reliability Coordinators

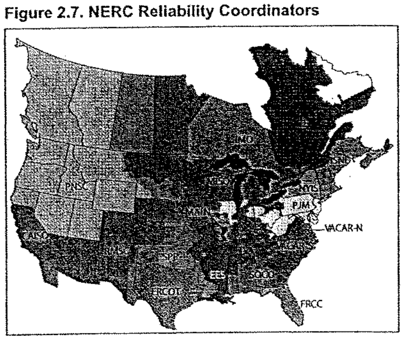


Figure 2.8. Reliability Coordinators and Control Areas in Ohio and Surrounding States

Dayton Power and Light, and Ohio Valley Electric Cooperative) and three generation-only control areas (Duke Energy's Washington County (Ohio) facility, Duke's Lawrence County/Hanging Rock (Ohio) facility, and Allegheny Energy's Buchanan (West Virginia) facility.

Reliability Responsibilities of Control Area Operators and Reliability Coordinators

1. **Control area operators have primary responsibility for reliability.** Their most important responsibilities, in the context of this report, are:

   N-1 criterion. NERC Operating Policy 2.A—Transmission Operations:

   > "All CONTROL AREAS shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency."

   Emergency preparedness and emergency response. NERC Operating Policy 5—Emergency Operations, General Criteria:

   > "Each system and CONTROL AREA shall promptly take appropriate action to relieve any abnormal conditions, which jeopardize reliable Interconnection operation."

   > "Each system, CONTROL AREA, and Region shall establish a program of manual and automatic load shedding which is designed to arrest frequency or voltage decays that could result in an uncontrolled failure of components of the interconnection."

Institutional Complexities and Reliability in the Midwest

The institutional arrangements for reliability in the Midwest are much more complex than they are in the Northeast the areas covered by the Northeast Power Coordinating Council (NPCC) and the Mid-Atlantic Area Council (MAAC). There are two principal reasons for this complexity. One is that in NPCC and MAAC, the independent system operator (ISO) also serves as the single control area operator for the individual member systems. In comparison, MISO provides reliability coordination for 35 control areas in the ECAR, MAIN, and MAPP regions and 2 others in the SPP region, and PJM provides reliability coordination for 8 control areas in the ECAR and MAIN regions (plus one in MAAC). (See table below.) This results in 18 control-area-to-control-area interfaces across the PJM/MISO reliability coordinator boundary.

The other is that MISO has less reliability-related authority over its control area members than PJM has over its members. Arguably, this lack of authority makes day-to-day reliability operations more challenging. Note, however, that (1) FERC's authority to require that MISO have greater authority over its members is limited, and (2) before approving MISO, FERC asked NERC for a formal assessment of whether reliability could be maintained under the arrangements proposed by MISO and PJM. After reviewing proposed plans for reliability coordination within and between PJM and MISO, NERC replied affirmatively but provisionally. NERC conducted audits in November and December 2002 of the MISO and PJM reliability plans, and some of the recommendations of the audit teams are still being addressed. The adequacy of the plans and whether the plans were being implemented as written are factors in the NERC's ongoing investigation.

Reliability Coordinator (RC)	Control Areas in RC Area	Regional Reliability Councils Affected and Number of Control Areas	Control Areas of Interest in RC Area
MISO	37	ECAR (12), MAIN (9), MAPP (14), SPP (2)	FE, Cinergy, Michigan Electric Coordinated System
PJM	9	MAAC (1), ECAR (7), MAIN (1)	PJM, AEP, Dayton Power & Light
ISO New England	2	NPCC (2)	ISONE, Maritimes
New York ISO	1	NPCC (1)	NYISO
Ontario Independent Market Operator	1	NPCC (1)	IMO
Trans-Energie	1	NPCC (1)	Hydro Québec

NERC Operating Policy 5.A—Coordination with Other Systems:

"A system, CONTROL AREA, or pool that is experiencing or anticipating an operating emergency shall communicate its current and future status to neighboring systems, CONTROL AREAS, or pools and throughout the interconnection.... A system shall inform other systems ... whenever ... the system's condition is burdening other systems or reducing the reliability of the Interconnection .... [or whenever] the system's line loadings and voltage/reactive levels are such that a single contingency could threaten the reliability of the Interconnection."

NERC Operating Policy 5.C—Transmission System Relief:

"Action to correct an OPERATING SECURITY LIMIT violation shall not impose unacceptable stress on internal generation or transmission equipment, reduce system reliability beyond acceptable limits, or unduly impose voltage or reactive burdens on neighboring systems. If all other means fail, corrective action may require load reduction."

Operating personnel and training: NERC Operating Policy 8.B—Training:

"Each OPERATING AUTHORITY should periodically practice simulated emergencies. The scenarios included in practice situations should represent a variety of operating conditions and emergencies."

What Constitutes an Operating Emergency?

An operating emergency is an unsustainable condition that cannot be resolved using the resources normally available. The NERC Operating Manual defines a "capacity emergency" as when a system's or pool's operating generation capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements. It defines an "energy emergency" as when a load-serving entity has exhausted all other options and can no longer provide its customers' expected energy requirements. A transmission emergency exists when "the system's line loadings and voltage/reactive levels are such that a single contingency could threaten the reliability of the Interconnection." Control room operators and dispatchers are given substantial latitude to determine when to declare an emergency. (See page 42 in Chapter 4 for more detail.)

2. **Reliability Coordinators** such as MISO and PJM are expected to comply with all aspects of NERC Operating Policies, especially Policy 9, Reliability Coordinator Procedures, and its appendices. Key requirements include:

NERC Operating Policy 9, Criteria for Reliability Coordinators, 5.2:

Have "detailed monitoring capability of the RELIABILITY AREA and sufficient monitoring capability of the surrounding RELIABILITY AREAS to ensure potential security violations are identified."

NERC Operating Policy 9, Functions of Reliability Coordinators, 1.7:

"Monitor the parameters that may have significant impacts within the RELIABILITY AREA and with neighboring RELIABILITY AREAS with respect to ... sharing with other RELIABILITY COORDINATORS any information regarding potential, expected, or actual critical operating conditions that could negatively impact other RELIABILITY AREAS. The RELIABILITY COORDINATOR will coordinate with other RELIABILITY COORDINATORS and CONTROL AREAS as needed to develop appropriate plans to mitigate negative impacts of potential, expected, or actual critical operating conditions...."

NERC Operating Policy 9, Functions of Reliability Coordinators, 6:

"Conduct security assessment and monitoring programs to assess contingency situations. Assessments shall be made in real time and for the operations planning horizon at the CONTROL AREA level with any identified problems reported to the RELIABILITY COORDINATOR. The RELIABILITY COORDINATOR is to ensure that CONTROL AREA, RELIABILITY AREA, and regional boundaries are sufficiently modeled to capture any problems crossing such boundaries."

Endnotes

[1]The province of Quebec, although considered a part of the Eastern Interconnection, is connected to the rest of the Eastern Interconnection primarily by DC ties. In this instance, the DC ties acted as buffers between portions of the Eastern Interconnection; transient disturbances propagate through them less readily. Therefore, the electricity system in Quebec was not affected by the outage, except for a small portion of the

province's load that is directly connected to Ontario by AC transmission lines. (Although DC ties can act as a buffer between systems, the tradeoff is that they do not allow instantaneous generation support following the unanticipated loss of a generating unit.)

[2] See, for example, *Maintaining Reliability in a Competitive Electric Industry* (1998), a report to the U.S. Secretary of Energy by the Task Force on Electric Systems Reliability; *National Energy Policy* (2001), a report to the President of the United States by the National Energy Policy Development Group, p. 7-6; and *National Transmission Grid Study* (2002), U.S. Dept. of Energy, pp. 46-48.

[3] The remaining three FE companies, Penelec, Met-Ed, and Jersey Central Power & Light, are in the NERC MAAC region and have PJM as their reliability coordinator. The focus of this report is on the portion of FE in ECAR reliability region and within the MISO reliability coordinator footprint.

3. Status of the Northeastern Power Grid Before the Blackout Sequence Began

Summary

This chapter reviews the state of the northeast portion of the Eastern Interconnection during the days prior to August 14, 2003 and up to 15:05 EDT on August 14 to determine whether conditions at that time were in some way unusual and might have contributed to the initiation of the blackout. The Task Force's investigators found that at 15:05 EDT, immediately before the tripping (automatic shutdown) of FirstEnergy's (FE) Harding-Chamberlin 345-kV transmission line, the system was able to be operated reliably following the occurrence of any of more than 800 contingencies, including the loss of the Harding-Chamberlin line. At that point the system was being operated near (but still within) prescribed limits and in compliance with NERC's operating policies.

Determining that the system was in a reliable operational state at that time is extremely significant for understanding the causes of the blackout. It means that none of the electrical conditions on the system before 15:05 EDT was a direct cause of the blackout. This eliminates a number of possible causes of the blackout, whether individually or in combination with one another, such as:

- High power flows to Canada
- System frequency variations
- Low voltages earlier in the day or on prior days
- Low reactive power output from IPPs
- Unavailability of individual generators or transmission lines.

It is important to emphasize that establishing whether conditions were normal or unusual prior to and on August 14 has no direct bearing on the responsibilities and actions expected of the organizations and operators who are charged with ensuring power system reliability. As described in Chapter 2, the electricity industry has developed and codified a set of mutually reinforcing reliability standards and practices to ensure that system operators are prepared for the unexpected. The basic assumption underlying these standards and practices is that power system elements will fail or become unavailable in unpredictable ways. Sound reliability management is designed to ensure that safe operation of the system will continue following the unexpected loss of any key element (such as a major generator or key transmission facility). These practices have been designed to maintain a functional and reliable grid, regardless of whether actual operating conditions are normal. It is a basic principle of reliability management that "operators must operate the system they have in front of them"— unconditionally.

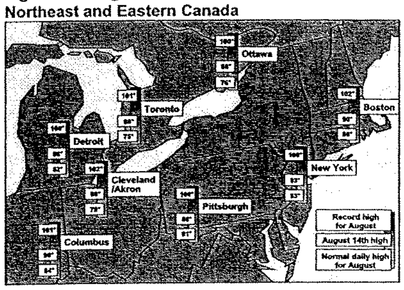
In terms of day-ahead planning, this means evaluating and if necessary adjusting the planned generation pattern (scheduled electricity transactions) to change the transmission flows, so that if a key facility were lost, the operators would still be able to readjust the remaining system and operate within safe limits. In terms of real-time operations, this means that the system should be operated at all times so as to be able to withstand the loss of any single facility and still remain within the system's thermal, voltage, and stability limits. If a facility is lost unexpectedly, the system operators must determine whether to make operational changes to ensure that the remaining system is able to withstand the loss of yet another key element and still remain able to operate within safe limits. This includes adjusting generator outputs, curtailing electricity transactions, and if necessary, shedding interruptible and firm customer load—i.e., cutting some customers off temporarily, and in the right locations, to reduce electricity demand to a level that matches what the system is then able to deliver safely.

Electric Demands on August 14

Temperatures on August 14 were above normal throughout the northeast region of the United

States and in eastern Canada. As a result, electricity demands were high due to high air conditioning loads typical of warm days in August, though not unusually so. System operators had successfully managed higher demands both earlier in the summer and in previous years. Recorded peak electric demands throughout the region on August 14 were below peak demands recorded earlier in the summer of 2003 (Figure 3.1).

Figure 3.1. August 2003 Temperatures in the U.S. Northeast and Eastern Canada



Power Flow Patterns

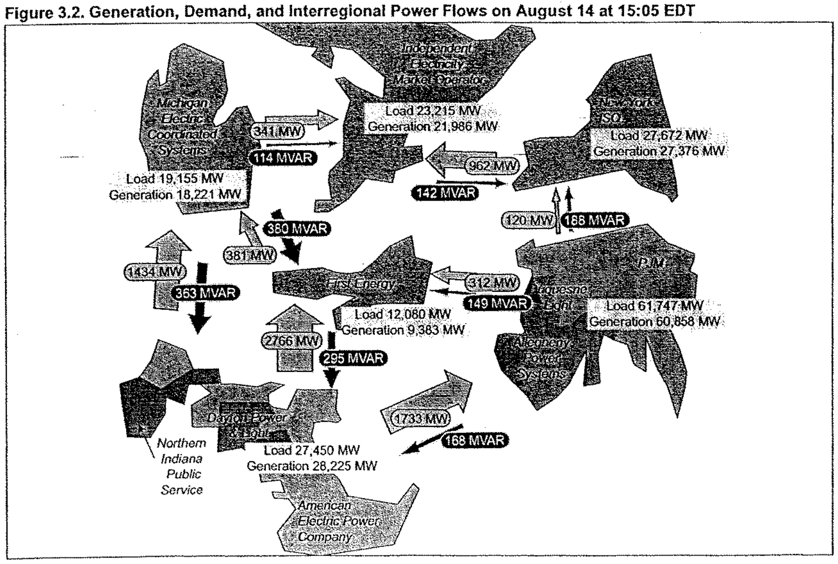
On August 14, the flow of power through the ECAR region was heavy as a result of large transfers of power from the south (Tennessee, Kentucky, Missouri, etc.) and west (Wisconsin, Minnesota, Illinois, etc.) to the north (Ohio, Michigan, and Ontario) and east (New York). The destinations for much of the power were northern Ohio, Michigan, PJM, and Ontario (Figure 3.2).

While heavy, these transfers were not beyond previous levels or in directions not seen before (Figure 3.3). The level of imports into Ontario on August 14 was high but not unusual, and well within IMO's import capability. Ontario's IMO is a frequent importer of power, depending on the availability and price of generation within Ontario. IMO had imported similar and higher amounts of power several times during the summers of 2002 and 2003.

System Frequency

Although system frequency on the Eastern Interconnection was somewhat more variable on

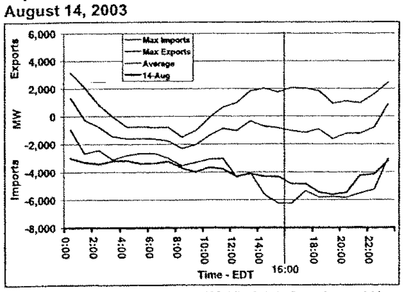
Figure 3.2. Generation, Demand, and Interregional Power Flows on August 14 at 15:05 EDT



August 14 prior to 15:05 EDT compared with recent history, it was well within the bounds of safe operating practices as outlined in NERC operating policies. As a result, system frequency variation was not a cause of the initiation of the blackout. But once the cascade was initiated, the large frequency swings that were induced became a principal means by which the blackout spread across a wide area (Figure 3.4).

> *Frequency Management*
>
> Each control area is responsible for maintaining a balance between its generation and demand. If persistent under-frequency occurs, at least one control area somewhere is "leaning on the grid," meaning that it is taking unscheduled electricity from the grid, which both depresses system frequency and creates unscheduled power flows. In practice, minor deviations at the control area level are routine; it is very difficult to maintain an exact balance between generation and demand. Accordingly, NERC has established operating rules that specify maximum permissible deviations, and focus on prohibiting persistent deviations, but not instantaneous ones. NERC monitors the performance of control areas through specific measures of control performance that gauge how accurately each control area matches its load and generation.

Figure 3.3. Northeast Central Area Scheduled Imports and Exports: Summer 2003 Compared to August 14, 2003



Note: Area covered includes ECAR, PJM, Ontario, and New York, without imports from the Maritime Provinces, ISO-New England, or Hydro-Quebec.

Assuming stable conditions, the system frequency is the same across an interconnected grid at any particular moment. System frequency will vary from moment to moment, however, depending on the second-to-second balance between aggregate generation and aggregate demand across the interconnection. System frequency is monitored on a continuous basis.

Generation Facilities Unavailable on August 14

Several key generators in the region were out of service going into the day of August 14. On any given day, some generation and transmission capacity is unavailable; some facilities are out for routine maintenance, and others have been forced out by an unanticipated breakdown and require repairs. August 14, 2003, was no exception (Table 3.1).

The generating units that were not available on August 14 provide real and reactive power directly to the Cleveland, Toledo, and Detroit areas. Under standard practice, system operators take into account the unavailability of such units and any

Figure 3.4. Frequency on August 14, 2003, up to 15:31 EDT

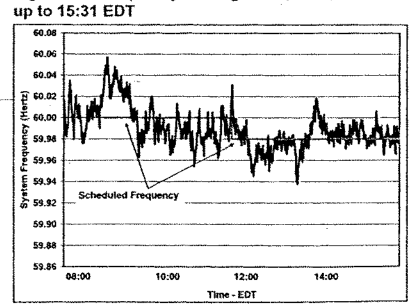


Table 3.1. Generators Not Available on August 14

Generator	Rating	Reason
Davis-Besse Nuclear Unit	750 MW	Prolonged NRC-ordered outage beginning on 3/22/02
Eastlake Unit 4	238 MW	Forced outage on 8/13/03
Monroe Unit 1	817 MW	Planned outage, taken out of service on 8/8/03
Cook Nuclear Unit 2	1,060 MW	Outage began on 8/13/03

transmission facilities known to be out of service in the day-ahead planning studies they perform to determine the condition of the system for the next day. Knowing the status of key facilities also helps operators determine in advance the safe electricity transfer levels for the coming day.

MISO's day-ahead planning studies for August 14 took these generator outages and known transmission outages into account and determined that the regional system could still be operated safely. The unavailability of these generation units and transmission facilities did not cause the blackout.

Voltages

During the days before August 14 and throughout the morning and mid-day on August 14, voltages were depressed in a variety of locations in northern Ohio because of high air conditioning demand and other loads, and power transfers into and across the region. (Unlike frequency, which is constant across the interconnection, voltage varies by location, and operators monitor voltages continuously at key locations across their systems.) However, actual measured voltage levels at key points on FE's transmission system on the morning of August 14 and up to 15:05 EDT were within the range previously specified by FE as acceptable. Note, however, that many control areas in the Eastern Interconnection have set their acceptable voltage bands at levels higher than that used by FE. For example, AEP's minimum acceptable voltage level is 95% of a line's nominal rating, as compared to FE's 92%.[1]

Voltage management is especially challenging on hot summer days because of high air conditioning requirements, other electricity demand, and high transfers of power for economic reasons, all of which increase the need for reactive power. Operators address these challenges through long-term planning, day-ahead planning, and real-time adjustments to operating equipment. On August 14, for example, PJM implemented routine voltage management procedures developed for heavy load conditions. FE also began preparations early in the afternoon of August 14, requesting capacitors to be restored to service[2] and additional voltage support from generators.[3] Such actions were typical of many system operators that day as well as on other days with high electric demand. As the day progressed, operators across the region took additional actions, such as increasing plants' reactive power output, plant redispatch, transformer tap changes, and increased use of capacitors to respond to changing voltage conditions.

The power flow data for northern Ohio on August 14 just before the Harding-Chamberlin line tripped at 15:05 EDT (Figure 3.2) show that FE's load was approximately 12,080 MW. FE was importing about 2,575 MW, 21% of its total system needs, and generating the remainder. With this high level of imports and high air conditioning loads in the

Independent Power Producers and Reactive Power

Independent power producers (IPPs) are power plants that are not owned by utilities. They operate according to market opportunities and their contractual agreements with utilities, and may or may not be under the direct control of grid operators. An IPP's reactive power obligations are determined by the terms of its contractual interconnection agreement with the local transmission owner. Under routine conditions, some IPPs provide limited reactive power because they are not required or paid to produce it; they are only paid to produce active power. (Generation of reactive power by a generator can require scaling back generation of active power.) Some contracts, however, compensate IPPs for following a voltage schedule set by the system operator, which requires the IPP to vary its output of reactive power as system conditions change. Further, contracts typically require increased reactive power production from IPPs when it is requested by the control area operator during times of a system emergency. In some contracts, provisions call for the payment of opportunity costs to IPPs when they are called on for reactive power (i.e., they are paid the value of foregone active power production).

Thus, the suggestion that IPPs may have contributed to the difficulties of reliability management on August 14 because they don't provide reactive power is misplaced. What the IPP is required to produce is governed by contractual arrangements, which usually include provisions for contributions to reliability, particularly during system emergencies. More importantly, it is the responsibility of system planners and operators, not IPPs, to plan for reactive power requirements and make any short-term arrangements needed to ensure that adequate reactive power resources will be available.

metropolitan areas around the southern end of Lake Erie, FE's system reactive power needs rose further. Investigation team modeling indicates that at 15:00 EDT, with Eastlake 5 out of service, FE was a net importer of about 132 MVAr. A significant amount of power also was flowing through northern Ohio on its way to Michigan and Ontario (Figure 3.2). The net effect of this flow pattern and load composition was to depress voltages in northern Ohio.

Unanticipated Outages of Transmission and Generation on August 14

Three significant unplanned outages occurred in the Ohio area on August 14 prior to 15:05 EDT. Around noon, several Cinergy transmission lines in south-central Indiana tripped; at 13:31 EDT, FE's Eastlake 5 generating unit along the southwestern shore of Lake Erie tripped; at 14:02 EDT, a Dayton Power and Light (DPL) line, the Stuart-Atlanta 345-kV line in southern Ohio, tripped.

- Transmission lines on the Cinergy 345-, 230-, and 138-kV systems experienced a series of outages starting at 12:08 EDT and remained out of service during the entire blackout. The loss of these lines caused significant voltage and loading problems in the Cinergy area. Cinergy made generation changes, and MISO operators responded by implementing transmission load relief (TLR) procedures to control flows on the transmission system in south-central Indiana. System modeling by the investigation team (see details below, page 20) showed that the loss of these lines was *not* electrically related to subsequent events in northern Ohio that led to the blackout.
- The DPL Stuart-Atlanta 345-kV line, linking DPL to AEP and monitored by the PJM reliability coordinator, tripped at 14:02 EDT. This was the result of a tree contact, and the line remained out of service during the entire blackout. As explained below, system modeling by the investigation team has shown that this outage was not a cause of the subsequent events in northern Ohio that led to the blackout. However, since the line was not in MISO's footprint, MISO operators did not monitor the status of this line, and did not know that it had gone out of service. This led to a data mismatch that prevented MISO's state estimator (a key monitoring tool) from producing usable results later in the day at a time when system conditions in FE's control area were deteriorating (see details below, page 27).
- Eastlake Unit 5 is a 597-MW generating unit located just west of Cleveland near Lake Erie. It is a major source of reactive power support for the Cleveland area. It tripped at 13:31. The cause of the trip was that as the Eastlake 5 operator sought to increase the unit's reactive power

Power Flow Simulation of Pre-Cascade Conditions

The bulk power system has no memory. It does not matter if frequencies or voltage were unusual an hour, a day, or a month earlier. What matters for reliability are loadings on facilities, voltages, and system frequency at a given moment and the collective capability of these system components at that same moment to withstand a contingency without exceeding thermal, voltage, or stability limits.

Power system engineers use a technique called power flow simulation to reproduce known operating conditions at a specific time by calibrating an initial simulation to observed voltages and line flows. The calibrated simulation can then be used to answer a series of "what if" questions to determine whether the system was in a safe operating state at that time. The "what if" questions consist of systematically simulating outages by removing key elements (e.g., generators or transmission lines) one by one and reassessing the system each time to determine whether line or voltage limits would be exceeded. If a limit is exceeded, the system is not in a secure state. As described in Chapter 2, NERC operating policies require operators, upon finding that their system is not in a reliable state, to take immediate actions to restore the system to a reliable state as soon as possible and within a maximum of 30 minutes.

To analyze the evolution of the system on the afternoon of August 14, this process was followed to model several points in time, corresponding to key transmission line trips. For each point, three solutions were obtained: (1) conditions immediately before a facility tripped off; (2) conditions immediately after the trip; and (3) conditions created by any automatic actions taken following the trip.

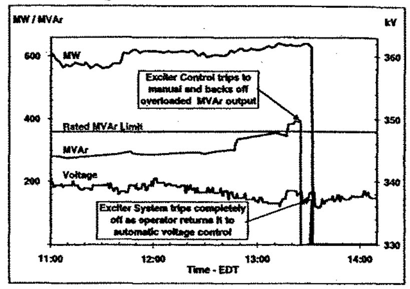
output (Figure 3.5), the unit's protection system detected a failure and tripped the unit off-line. The loss of the Eastlake 5 unit did not put the grid into an unreliable state—i.e., it was still able to withstand safely another contingency. However, the loss of the unit required FE to import additional power to make up for the loss of the unit's output (540 MW), made voltage management in northern Ohio more challenging, and gave FE operators less flexibility in operating their system (see details below, page 27).

Model-Based Analysis of the State of the Regional Power System at 15:05 EDT, Before the Loss of FE's Harding-Chamberlin 345-kV Line

As the first step in modeling the evolution of the August 14 blackout, the investigative team established a base case by creating a power flow simulation for the entire Eastern Interconnection and benchmarking it to recorded system conditions at 15:05 EDT on August 14. The team started with a projected summer 2003 power flow case developed in the spring of 2003 by the Regional Reliability Councils to establish guidelines for safe operations for the coming summer. The level of detail involved in this region-wide study far exceeds that normally considered by individual control areas and reliability coordinators. It consists of a detailed representation of more than 43,000 buses (points at which lines, transformers, and/or generators converge), 57,600 transmission lines, and all major generating stations across the northern U.S. and eastern Canada. The team then revised the summer power flow case to match recorded generation, demand, and power interchange levels among control areas at 15:05 EDT on August 14. The benchmarking consisted of matching the calculated voltages and line flows to recorded observations at more than 1,500 locations within the grid. Thousands of hours of effort were required to benchmark the model satisfactorily to observed conditions at 15:05 EDT.

Once the base case was benchmarked, the team ran a contingency analysis that considered more than 800 possible events as points of departure from the 15:05 EDT case. None of these contingencies resulted in a violation of a transmission line loading or bus voltage limit prior to the trip of FE's

Figure 3.5. MW and MVAr Output from Eastlake Unit 5 on August 14



Harding-Chamberlin 345-kV line. That is, according to these simulations, the system at 15:05 EDT was able to be operated safely following the occurrence of any of the tested contingencies. From an electrical standpoint, therefore, the Eastern Interconnection was then being operated within all established limits and in full compliance with NERC's operating policies. However, after loss of the Harding-Chamberlin 345-kV line, the system would have exceeded emergency ratings on several lines for two of the contingencies studied. In other words, it would no longer be operating in compliance with NERC operating policies.

Conclusion

Determining that the system was in a reliable operational state at 15:05 EDT is extremely significant for understanding the causes of the blackout. It means that none of the electrical conditions on the system before 15:05 EDT was a cause of the blackout. This eliminates high power flows to Canada, unusual system frequencies, low voltages earlier in the day or on prior days, and the unavailability of individual generators or transmission lines, either individually or in combination with one another, as direct, principal or sole causes of the blackout.

Endnotes

[1] DOE/NERC fact-finding meeting, September 2003, statement by Mr. Steve Morgan (FE), PR0890803, lines 5-23.

[2] Transmission operator at FE requested the restoration of the Avon Substation capacitor bank #2. Example at Channel 3, 13:33:40.

[3] From 13:13 through 13:28, reliability operator at FE called nine plant operators to request additional voltage support. Examples at Channel 16, 13:13:18, 13:15:49, 13:16:44, 13:20:44, 13:22:07, 13:23:24, 13:24:38, 13:26:04, 13:28:40.

4. How and Why the Blackout Began

Summary

This chapter explains the major events—electrical, computer, and human—that occurred as the blackout evolved on August 14, 2003, and identifies the causes of the initiation of the blackout. It also lists initial findings concerning violations of NERC reliability standards. It presents facts collected by the investigation team and does not offer speculative or unconfirmed information or hypotheses. Some of the information presented here, such as the timing of specific electrical events, updates the Sequence of Events[1] released earlier by the Task Force.

The period covered in this chapter begins at 12:15 Eastern Daylight Time (EDT) on August 14, 2003 when inaccurate input data rendered MISO's state estimator (a system monitoring tool) ineffective. At 13:31 EDT, FE's Eastlake 5 generation unit tripped and shut down automatically. Shortly after 14:14 EDT, the alarm and logging system in FE's control room failed and was not restored until after the blackout. After 15:05 EDT, some of FE's 345-kV transmission lines began tripping out because the lines were contacting overgrown trees within the lines' right-of-way areas.

By around 15:46 EDT when FE, MISO and neighboring utilities had begun to realize that the FE system was in jeopardy, the only way that the blackout might have been averted would have been to drop at least 1,500 to 2,500 MW of load around Cleveland and Akron, and at this time the amount of load reduction required was increasing rapidly. No such effort was made, however, and by 15:46 EDT it may already have been too late regardless of any such effort. After 15:46 EDT, the loss of some of FE's key 345-kV lines in northern Ohio caused its underlying network of 138-kV lines to begin to fail, leading in turn to the loss of FE's Sammis-Star 345-kV line at 16:06 EDT. The chapter concludes with the loss of FE's Sammis-Star line, the event that triggered the uncontrollable cascade portion of the blackout sequence.

The loss of the Sammis-Star line triggered the cascade because it shut down the 345-kV path into northern Ohio from eastern Ohio. Although the area around Akron, Ohio was already blacked out due to earlier events, most of northern Ohio remained interconnected and electricity demand was high. This meant that the loss of the heavily overloaded Sammis-Star line instantly created major and unsustainable burdens on lines in adjacent areas, and the cascade spread rapidly as lines and generating units automatically took themselves out of service to avoid physical damage.

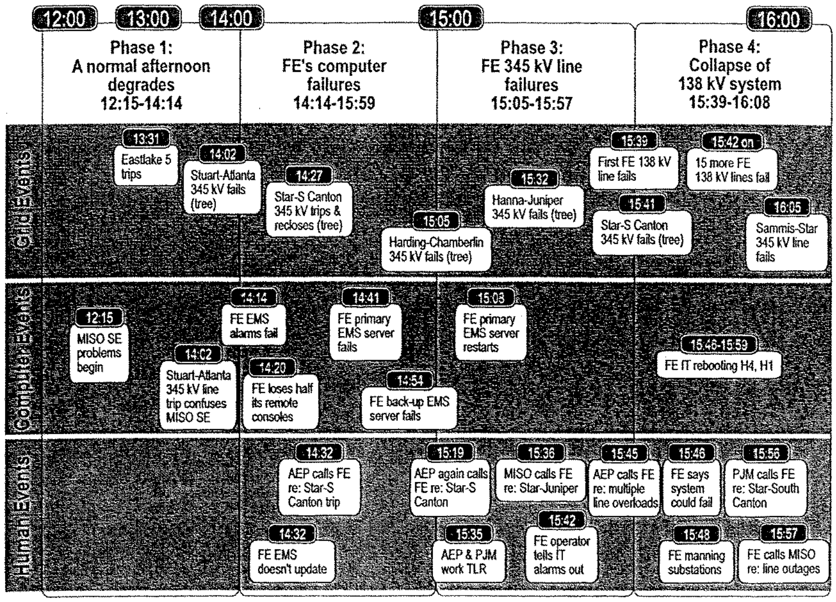
Chapter Organization

This chapter is divided into several phases that correlate to major changes within the FirstEnergy system and the surrounding area in the hours leading up to the cascade:

- **Phase 1:** A normal afternoon degrades
- **Phase 2:** FE's computer failures
- **Phase 3:** Three FE 345-kV transmission line failures and many phone calls
- **Phase 4:** The collapse of the FE 138-kV system and the loss of the Sammis-Star line

Key events within each phase are summarized in Figure 4.1, a timeline of major events in the origin of the blackout in Ohio. The discussion that follows highlights and explains these significant events within each phase and explains how the events were related to one another and to the cascade.

Figure 4.1. Timeline: Start of the Blackout in Ohio



Phase 1: A Normal Afternoon Degrades: 12:15 EDT to 14:14 EDT

Overview of This Phase

Northern Ohio was experiencing an ordinary August afternoon, with loads moderately high to serve air conditioning demand. FirstEnergy (FE) was importing approximately 2,000 MW into its service territory, causing its system to consume high levels of reactive power. With two of Cleveland's active and reactive power production anchors already shut down (Davis-Besse and Eastlake 4), the loss of the Eastlake 5 unit at 13:31 further depleted critical voltage support for the Cleveland-Akron area. Detailed simulation modeling reveals that the loss of Eastlake 5 was a significant factor in the outage later that afternoon—with Eastlake 5 gone, transmission line loadings were notably higher and after the loss of FE's Harding-Chamberlin line at 15:05, the system eventually became unable to sustain additional contingencies without line overloads above emergency ratings. Had Eastlake 5 remained in service, subsequent line loadings would have been lower and tripping due to tree contacts may not have occurred. Loss of Eastlake 5, however, did not initiate the blackout. Subsequent computer failures leading to the loss of situational awareness in FE's control room and the loss of key FE transmission lines due to contacts with trees were the most important causes.

At 14:02 EDT, Dayton Power & Light's (DPL) Stuart-Atlanta 345-kV line tripped off-line due to a tree contact. This line had no direct electrical effect on FE's system—but it did affect MISO's performance as reliability coordinator, even though PJM is the reliability coordinator for the DPL line. One of MISO's primary system condition evaluation tools, its state estimator, was unable to assess system conditions for most of the period between 12:37 EDT and 15:34 EDT, due to a combination of human error and the effect of the loss of DPL's

The Causes of the Blackout

The initiation of the August 14, 2003, blackout was caused by deficiencies in specific practices, equipment, and human decisions that coincided that afternoon. There were three groups of causes:

Group 1: Inadequate situational awareness at FirstEnergy Corporation (FE). In particular:

A) FE failed to ensure the security of its transmission system after significant unforeseen contingencies because it did not use an effective contingency analysis capability on a routine basis. (See page 28.)

B) FE lacked procedures to ensure that their operators were continually aware of the functional state of their critical monitoring tools. (See page 31.)

C) FE lacked procedures to test effectively the functional state of these tools after repairs were made. (See page 31.)

D) FE did not have additional monitoring tools for high-level visualization of the status of their transmission system to facilitate its operators' understanding of transmission system conditions after the failure of their primary monitoring/alarming systems. (See page 33.)

Group 2: FE failed to manage adequately tree growth in its transmission rights-of-way. This failure was the common cause of the outage of three FE 345-kV transmission lines. (See page 34.)

Group 3: Failure of the interconnected grid's reliability organizations to provide effective diagnostic support. In particular:

A) MISO did not have real-time data from Dayton Power and Light's Stuart-Atlanta 345-kV line incorporated into its state estimator (a system monitoring tool). This precluded MISO from becoming aware of FE's system problems earlier and providing diagnostic assistance to FE. (See page 24.)

B) MISO's reliability coordinators were using non-real-time data to support real-time "flowgate" monitoring. This prevented MISO from detecting an N-1 security violation in FE's system and from assisting FE in necessary relief actions. (See page 39.)

C) MISO lacked an effective means of identifying the location and significance of transmission line breaker operations reported by their Energy Management System (EMS). Such information would have enabled MISO operators to become aware earlier of important line outages. (See pages 27 and 36.)

D) PJM and MISO lacked joint procedures or guidelines on when and how to coordinate a security limit violation observed by one of them in the other's area due to a contingency near their common boundary. (See page 38.)

In the pages below, sections that relate to particular causes are denoted with the following symbols:

Cause 1: Inadequate Situational Awareness

Cause 2: Inadequate Tree Trimming

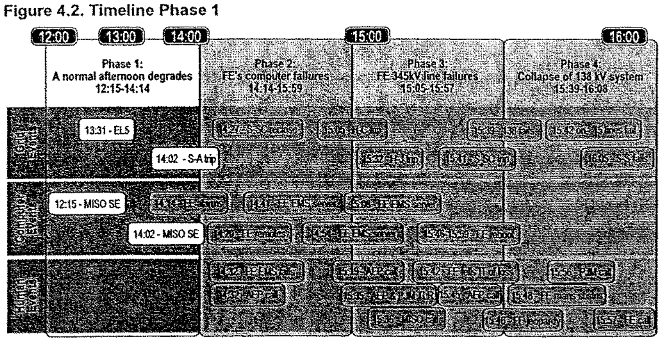
Cause 3: Inadequate RC Diagnostic Support

Stuart-Atlanta line on other MISO lines as reflected in the state estimator's calculations. Without an effective state estimator, MISO was unable to perform contingency analyses of generation and line losses within its reliability zone. Therefore, through 15:34 EDT MISO could not determine that with Eastlake 5 down, other transmission lines would overload if FE lost a major transmission line, and could not issue appropriate warnings and operational instructions.

In the investigation interviews, all utilities, control area operators, and reliability coordinators indicated that the morning of August 14 was a reasonably typical day. FE managers referred to it as peak load conditions on a less than peak load day.[2] Dispatchers consistently said that while voltages were low, they were consistent with historical voltages.[3] Throughout the morning and early afternoon of August 14, FE reported a growing need for voltage support in the upper Midwest.

The FE reliability operator was concerned about low voltage conditions on the FE system as early as 13:13 EDT. He asked for voltage support (i.e., increased reactive power output) from FE's

Figure 4.2. Timeline Phase 1



interconnected generators. Plants were operating in automatic voltage control mode (reacting to system voltage conditions and needs rather than constant reactive power output). As directed in FE's Manual of Operations,[4] the FE reliability operator began to call plant operators to ask for additional voltage support from their units. He noted to most of them that system voltages were sagging "all over." Several mentioned that they were already at or near their reactive output limits. None were asked to reduce their active power output to be able to produce more reactive output. He called the Sammis plant at 13:13 EDT, West Lorain at 13:15 EDT, Eastlake at 13:16 EDT, made three calls to unidentified plants between 13:20 EDT and 13:23 EDT, a "Unit 9" at 13:24 EDT, and two more at 13:26 EDT and 13:28 EDT.[5] The operators worked to get shunt capacitors at Avon that were out of service restored to support voltage.[6]

Following the loss of Eastlake 5 at 13:31 EDT, FE's operators' concern about voltage levels was heightened. They called Bayshore at 13:41 EDT and Perry at 13:43 EDT to ask the plants for more voltage support. Again, while there was substantial effort to support voltages in the Ohio area, First Energy personnel characterized the conditions as not being unusual for a peak load day, although this was not an all-time (or record) peak load day.

Key Phase 1 Events

1A) 12:15 EDT to 16:04 EDT: MISO's state estimator software solution was compromised, and MISO's single contingency reliability assessment became unavailable.

1B) 13:31:34 EDT: Eastlake Unit 5 generation tripped in northern Ohio.

1C) 14:02 EDT: Stuart-Atlanta 345-kV transmission line tripped in southern Ohio.

1A) MISO's State Estimator Was Turned Off: 12:15 EDT to 16:04 EDT

It is common for reliability coordinators and control areas to use a tool called a state estimator (SE) to improve the accuracy of the raw sampled data they have for the electric system by mathematically processing raw data to make it consistent with the electrical system model. The resulting information on equipment voltages and loadings is used in software tools such as real time contingency analysis (RTCA) to simulate various conditions and outages to evaluate the reliability of the power system. The RTCA tool is used to alert operators if the system is operating insecurely; it can be run either on a regular schedule (e.g., every 5 minutes), when triggered by some system event (e.g., the loss of a power plant or transmission line), or when initiated by an operator. MISO usually runs the SE every 5 minutes, and the RTCA less frequently. If the model does not have accurate and timely information about key pieces of system equipment or if key input data are wrong, the state estimator may be unable to reach a solution or it will reach a solution that is labeled as having a high degree of error. MISO considers its SE and RTCA tools to be still under development and not fully mature.

On August 14 at about 12:15 EDT, MISO's state estimator produced a solution with a high mismatch (outside the bounds of acceptable error). This was traced to an outage of Cinergy's

Initial Findings: Violations of NERC Reliability Standards

Note: These are initial findings and subject to further review by NERC. Additional violations may be identified.

Violation Number 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.[a]

Reference: NERC Operating Policy 2:

Following a contingency or other event that results in an OPERATING SECURITY LIMIT violation, the CONTROL AREA shall return its transmission system to within OPERATING SECURITY LIMITS soon as possible, but no longer than 30 minutes.

Violation Number 2. FE did not notify other systems of an impending system emergency.[b]

Reference: NERC Operating Policy 5:

Notifying other systems. A system shall inform other systems in their Region or subregion, through predetermined communication paths, whenever the following situations are anticipated or arise:

System is burdening others. The system's condition is burdening other systems or reducing the reliability of the Interconnection.

Lack of single contingency coverage. The system's line loadings and voltage/reactive levels are such that a single contingency could threaten the reliability of the Interconnection.

Violation Number 3. FE's state estimation/contingency analysis tools were not used to assess the system conditions.[c]

Reference: NERC Operating Policy 5:

Sufficient information and analysis tools shall be provided to the SYSTEM OPERATOR to determine the cause(s) of OPERATING SECURITY LIMIT violations. This information shall be provided in both real time and predictive formats so that the appropriate corrective actions may be taken.

Violation Number 4. FE operator training was inadequate for maintaining reliable operation.[d]

Reference: NERC Operating Policy 8:

SYSTEM OPERATOR Training. Each OPERATING AUTHORITY shall provide its SYSTEM OPERATORS with a coordinated training program that is designed to promote reliable operation. This program shall include:

- *Training staff. Individuals competent in both knowledge of system operations and instructional capabilities.*
- *Verification of achievement. Verification that all trainees have successfully demonstrated attainment of all required training objectives, including documented assessment of their training progress.*
- *Review. Periodic review to ensure that training materials are technically accurate and complete and to ensure that the training program continues to meet its objectives.*

Violation Number 5. MISO did not notify other reliability coordinators of potential problems.[e]

Reference: NERC Operating Policy 9:

Notify RELIABILITY COORDINATORS of potential problems. The RELIABILITY COORDINATOR who foresees a transmission problem within his RELIABILITY AREA shall issue an alert to all CONTROL AREAS and Transmission Providers in his RELIABILITY AREA, and all RELIABILITY COORDINATORS within the INTERCONNECTION via the RCIS without delay.

(continued on following page)

[a]Investigation team modeling showed that following the loss of the Chamberlin-Harding 345-kV line the system was beyond its OPERATING SECURITY LIMIT; i.e., the loss of the next most severe contingency would have resulted in other lines exceeding their emergency limits. Blackout causes 1A, 1B, 1E.

[b]DOE on-site interviews; comparative review of FE and MISO phone transcripts of 14 August; no calls found of FE declaring an emergency to MISO in either set of transcripts. Blackout causes 1A, 1B, 1D, 1E.

[c]DOE on-site interviews; Mr. Morgan, September 8 and 9 transcripts.

[d]Site visit by interviewers from Operations Team.

[e]MISO site visit and DOE interviews; Oct 1-3 Newark meetings, ns100303.pdf; Harzey-Cauley conversation, pages 111-119; blackout cause 3D.

Initial Findings: Violations of NERC Reliability Standards (Continued)

Violation Number 6. MISO did not have adequate monitoring capability.[f]

Reference: NERC Operating Policy 9, Appendix 9D:

Adequate facilities. Must have the facilities to perform their responsibilities, including:

- *Detailed monitoring capability of the RELIABILITY AREA and sufficient monitoring capability of the surrounding RELIABILITY AREAS to ensure potential security violations are identified.*

Continuous monitoring of Reliability Area. Must ensure that its RELIABILITY AREA of responsibility is continuously and adequately monitored. This includes the provisions for backup facilities.

[f]DOE interviews and Operations Team site visit. Oct 1-3 Newark meetings, ns100303.pdf; Harzey-Cauley conversation, pages 111-119; blackout causes 3A, 3B, 3C.

Energy Management System (EMS) and Decision Support Tools

Operators look at potential problems that could arise on their systems by using contingency analyses, driven from state estimation, that are fed by data collected by the SCADA system.

SCADA: System operators use System Control and Data Acquisition systems to acquire power system data and control power system equipment. SCADA systems have three types of elements: field remote terminal units (RTUs), communication to and between the RTUs, and one or more Master Stations.

Field RTUs, installed at generation plants and substations, are combination data gathering and device control units. They gather and provide information of interest to system operators, such as the status of a breaker (switch), the voltage on a line or the amount of power being produced by a generator, and execute control operations such as opening or closing a breaker. Telecommunications facilities, such as telephone lines or microwave radio channels, are provided for the field RTUs so they can communicate with one or more SCADA Master Stations or, less commonly, with each other.

Master stations are the pieces of the SCADA system that initiate a cycle of data gathering from the field RTUs over the communications facilities, with the time cycles ranging from every few seconds to as long as several minutes. In many power systems, Master Stations are fully integrated into the control room, serving as the direct interface to the Energy Management System (EMS), receiving incoming data from the field RTUs and relaying control operations commands to the field devices for execution.

State Estimation: Transmission system operators have visibility (condition information) over their own transmission facilities. Most control facilities do not receive direct line voltage and current data on every facility for which they need visibility. Instead, system state estimators use the real-time data measurements available on a subset of those facilities in a complex mathematical model of the power system that reflects the configuration of the network (which facilities are in service and which are not) and real-time system condition data to estimate voltage at each bus, and to estimate real and reactive power flow quantities on each line or through each transformer. Reliability coordinators and control areas that have them commonly run a state estimator on regular intervals or only as the need arises (i.e., upon demand). Not all control areas use state estimators.

Contingency Analysis: Given the state estimator's representation of current system conditions, a system operator or planner uses contingency analysis to analyze the impact of specific outages (lines, generators, or other equipment) or higher load, flow, or generation levels on the security of the system. The contingency analysis should identify problems such as line overloads or voltage violations that will occur if a new event (contingency) happens on the system. Some transmission operators and control areas have and use state estimators to produce base cases from which to analyze next contingencies ("N-1," meaning normal system minus 1 element) from the current conditions. This tool is typically used to assess the reliability of system operation. Many control areas do not use real time contingency analysis tools, but others run them on demand following potentially significant system events.

Bloomington-Denois Creek 230-kV line—although it was out of service, its status was not updated in MISO's state estimator. Line status information within MISO's reliability coordination area is transmitted to MISO by the ECAR data network or direct links and intended to be automatically linked to the SE. This requires coordinated data naming as well as instructions that link the data to the tools. For this line, the automatic linkage of line status to the state estimator had not yet been established (this is an ongoing project at MISO). The line status was corrected and MISO's analyst obtained a good SE solution at 13:00 EDT and an RTCA solution at 13:07 EDT, but to troubleshoot this problem he had turned off the automatic trigger that runs the state estimator every five minutes. After fixing the problem he forgot to re-enable it, so although he had successfully run the SE and RTCA manually to reach a set of correct system analyses, the tools were not returned to normal automatic operation. Thinking the system had been successfully restored, the analyst went to lunch.

Cause 3: Inadequate RC Diagnostic Support

The fact that the state estimator was not running automatically on its regular 5-minute schedule was discovered about 14:40 EDT. The automatic trigger was re-enabled but again the state estimator failed to solve successfully. This time investigation identified the Stuart-Atlanta 345-kV line outage (14:02 EDT) to be the likely cause.[7] This line is jointly owned by Dayton Power and Light and AEP and is monitored by Dayton Power and Light and is under PJM's reliability umbrella rather than MISO's. Even though it affects electrical flows within MISO, its status had not been automatically linked to MISO's SE.

The discrepancy between actual measured system flows (with Stuart-Atlanta off-line) and the MISO model (which assumed Stuart-Atlanta on-line) prevented the state estimator from solving correctly. At 15:09 EDT, when informed by the system engineer that the Stuart-Atlanta line appeared to be the problem, the MISO operator said (mistakenly) that this line was in service. The system engineer then tried unsuccessfully to reach a solution with the Stuart-Atlanta line modeled as in service until approximately 15:29 EDT, when the MISO operator called PJM to verify the correct status. After they determined that Stuart-Atlanta had tripped, they updated the state estimator and it solved successfully. The RTCA was then run manually and solved successfully at 15:41 EDT. MISO's state estimator and contingency analysis were back under full automatic operation and solving effectively by 16:04 EDT, about two minutes before the initiation of the cascade.

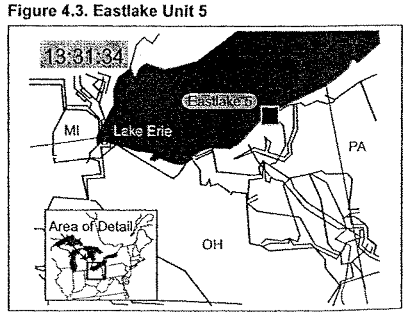
In summary, the MISO state estimator and real time contingency analysis tools were effectively out of service between 12:15 EDT and 16:04 EDT. This prevented MISO from promptly performing precontingency "early warning" assessments of power system reliability over the afternoon of August 14.

1B) Eastlake Unit 5 Tripped: 13:31 EDT

Eastlake Unit 5 (rated at 597 MW) is in northern Ohio along the southern shore of Lake Erie, connected to FE's 345-kV transmission system (Figure 4.3). The Cleveland and Akron loads are generally supported by generation from a combination of the Eastlake and Davis-Besse units, along with significant imports, particularly from 9,100 MW of generation located along the Ohio and Pennsylvania border. The unavailability of Eastlake 4 and Davis-Besse meant that FE had to import more energy into the Cleveland area (either from its own plants or from or through neighboring utilities) to support its load.

When Eastlake 5 dropped off-line, flows caused by replacement power transfers and the associated reactive power to support the imports to the local area contributed to the additional line loadings in the region. At 15:00 EDT on August 14, FE's load was approximately 12,080 MW. They were importing about 2,575 MW, 21% of their total. With this high level of imports, FE's system reactive power needs rose further. Investigation team modeling indicates that at about 15:00 EDT, FE's

Figure 4.3. Eastlake Unit 5



system was consuming so much reactive power that it was a net importer, bringing in about 132 MVAr.

The investigation team's system simulations indicate that the loss of Eastlake 5 was a critical step in the sequence of events. Contingency analysis simulation of the conditions following the loss of the Harding-Chamberlin 345-kV circuit at 15:05 EDT showed that the system would be unable to sustain some contingencies without line overloads above emergency ratings. However, when Eastlake 5 was modeled as in service and fully available in those simulations, all overloads above emergency limits were eliminated even with the loss of Harding-Chamberlin.

Cause 1: Inadequate Situational Awareness

FE did not perform a contingency analysis after the loss of Eastlake 5 at 13:31 EDT to determine whether the loss of further lines or plants would put their system at risk. FE also did not perform a contingency analysis after the loss of Harding-Chamberlin at 15:05 EDT (in part because they did not know that it had tripped out of service), nor does the utility routinely conduct such studies.[8] Thus FE did not discover that their system was no longer in an N-1 secure state at 15:05 EDT, and that operator action was needed to remedy the situation.

1C) Stuart-Atlanta 345-kV Line Tripped: 14:02 EDT

Cause 3: Inadequate RC Diagnostic Support

The Stuart-Atlanta 345-kV transmission line is in the control area of Dayton Power and Light.[9] At 14:02 EDT the line tripped due to contact with a tree, causing a short circuit to ground, and locked out. Investigation team modeling reveals that the loss of DPL's Stuart-Atlanta line had no significant electrical effect on power flows and voltages in the FE area. The team examined the security of FE's system, testing power flows and voltage levels with the combination of plant and line outages that evolved on the afternoon of August 14. This analysis shows that the availability or unavailability of the Stuart-Atlanta 345-kV line did not change the capability or performance of FE's system or affect any line loadings within the FE system, either immediately after its trip or later that afternoon. Again, the only reason why Stuart-Atlanta matters to the blackout is because it contributed to the failure of MISO's state estimator to operate effectively, so MISO could not fully identify FE's precarious system conditions until 16:04 EDT.

Phase 2: FE's Computer Failures: 14:14 EDT to 15:59 EDT

Overview of This Phase

Starting around 14:14 EDT, FE's control room operators lost the alarm function that provided audible and visual indications when a significant piece of equipment changed from an acceptable to problematic condition. Shortly thereafter, the EMS system lost a number of its remote control consoles. Next it lost the primary server computer that was hosting the alarm function, and then the backup server such that all functions that were being supported on these servers were stopped at 14:54 EDT. However, for over an hour no one in FE's control room grasped that their computer systems were not operating properly, even though FE's Information Technology support staff knew of the problems and were working to solve them, and the absence of alarms and other symptoms offered many clues to the operators of the EMS system's impaired state. Thus, without a functioning EMS or the knowledge that it had failed, FE's system operators remained unaware that their electrical system condition was beginning to degrade. Unknowingly, they used the outdated system condition information they did have to discount information from others about growing system problems.

Key Events in This Phase

2A) 14:14 EDT: FE alarm and logging software failed. Neither FE's control room operators nor FE's IT EMS support personnel were aware of the alarm failure.

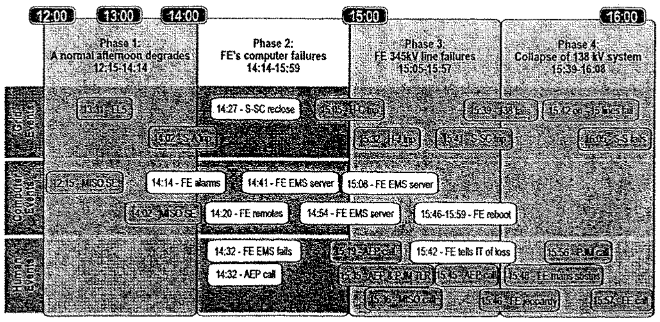
2B) 14:20 EDT: Several FE remote location consoles failed. FE Information Technology (IT) engineer was computer auto-paged.

2C) 14:27:16 EDT: Star-South Canton 345-kV transmission line tripped and successfully reclosed.

2D) 14:32 EDT: AEP called FE control room about AEP indication of Star-South Canton 345-kV line trip and reclosure. FE had no alarm or log of this line trip.

2E) 14:41 EDT: The primary FE control system server hosting the alarm function failed. Its applications and functions were passed over to a backup computer. FE's IT engineer was auto-paged.

Figure 4.4. Timeline Phase 2



2F) 14:54 EDT: The FE back-up computer failed and all functions that were running on it stopped. FE's IT engineer was auto-paged.

Failure of FE's Alarm System

Cause 1: Inadequate Situational Awareness

FE's computer SCADA alarm and logging software failed sometime shortly after 14:14 EDT (the last time that a valid alarm came in). After that time, the FE control room consoles did not receive any further alarms nor were there any alarms being printed or posted on the EMS's alarm logging facilities. Power system operators rely heavily on audible and on-screen alarms, plus alarm logs, to reveal any significant changes in their system's conditions. After 14:14 EDT on August 14, FE's operators were working under a significant handicap without these tools. However, they were in further jeopardy because they did not know that they were operating without alarms, so that they did not realize that system conditions were changing.

Alarms are a critical function of an EMS, and EMS-generated alarms are the fundamental means by which system operators identify events on the power system that need their attention. Without alarms, events indicating one or more significant system changes can occur but remain undetected by the operator. If an EMS's alarms are absent, but operators are aware of the situation and the remainder of the EMS's functions are intact, the operators can potentially continue to use the EMS to monitor and exercise control of their power system. In such circumstances, the operators would have to do so via repetitive, continuous manual scanning of numerous data and status points located within the multitude of individual displays available within their EMS. Further, it would be difficult for the operator to identify quickly the most relevant of the many screens available.

Although the alarm processing function of FE's EMS failed, the remainder of that system generally continued to collect valid real-time status information and measurements about FE's power system, and continued to have supervisory control over the FE system. The EMS also continued to send its normal and expected collection of information on to other monitoring points and authorities, including MISO and AEP. Thus these entities continued to receive accurate information about the status and condition of FE's power system even past the point when FE's EMS alarms failed. FE's operators were unaware that in this situation they needed to manually and more closely monitor and interpret the SCADA information they were receiving. Continuing on in the belief that their system was satisfactory and lacking any alarms from their EMS to the contrary, FE control room operators were subsequently surprised when they began receiving telephone calls from other locations and information sources—MISO, AEP, PJM, and FE field operations staff—who offered information on the status of FE's transmission facilities that conflicted with FE's system operators' understanding of the situation.

Analysis of the alarm problem performed by FE suggests that the alarm process essentially "stalled" while processing an alarm event, such that the process began to run in a manner that failed to complete the processing of that alarm or produce any other valid output (alarms). In the meantime, new inputs—system condition data that needed to be reviewed for possible alarms—built up in and then overflowed the process' input buffers.[10]

Loss of Remote EMS Terminals. Between 14:20 EDT and 14:25 EDT, some of FE's remote control terminals in substations ceased operation. FE has advised the investigation team that it believes this occurred because the data feeding into those terminals started "queuing" and overloading the terminals' buffers. FE's system operators did not learn about this failure until 14:36 EDT, when a technician at one of the sites noticed the terminal was not working after he came in on the 15:00 shift, and called the main control room to report the problem. As remote terminals failed, each triggered an automatic page to FE's Information Technology (IT) staff.[11] The investigation team has not determined why some terminals failed whereas others did not. Transcripts indicate that data links to the remote sites were down as well.[12]

EMS Server Failures. FE's EMS system includes several server nodes that perform the higher functions of the EMS. Although any one of them can host all of the functions, FE's normal system configuration is to have a number of host subsets of the applications, with one server remaining in a "hot-standby" mode as a backup to the others should any fail. At 14:41 EDT, the primary server hosting the EMS alarm processing application failed, due either to the stalling of the alarm application, "queuing" to the remote terminals, or some combination of the two. Following preprogrammed instructions, the alarm system

Alarms

System operators must keep a close and constant watch on the multitude of things occurring simultaneously on their power system. These include the system's load, the generation and supply resources to meet that load, available reserves, and measurements of critical power system states, such as the voltage levels on the lines. Because it is not humanly possible to watch and understand all these events and conditions simultaneously, Energy Management Systems use alarms to bring relevant information to operators' attention. The alarms draw on the information collected by the SCADA real-time monitoring system.

Alarms are designed to quickly and appropriately attract the power system operator's attention to events or developments of interest on the system. They do so using combinations of audible and visual signals, such as sounds at operators' control desks and symbol or color changes or animations on system monitors or displays. EMS alarms for power systems are similar to the indicator lights or warning bell tones that a modern automobile uses to signal its driver, like the "door open" bell, an image of a headlight high beam, a "parking brake on" indicator, and the visual and audible alert when a gas tank is almost empty.

Power systems, like cars, use "status" alarms and "limit" alarms. A status alarm indicates the state of a monitored device. In power systems these are commonly used to indicate whether such items as switches or breakers are "open" or "closed" (off or on) when they should be otherwise, or whether they have changed condition since the last scan. These alarms should provide clear indication and notification to system operators of whether a given device is doing what they think it is, or what they want it to do—for instance, whether a given power line is connected to the system and moving power at a particular moment.

EMS limit alarms are designed to provide an indication to system operators when something important that is measured on a power system device—such as the voltage on a line or the amount of power flowing across it—is below or above pre-specified limits for using that device safely and efficiently. When a limit alarm activates, it provides an important early warning to the power system operator that elements of the system may need some adjustment to prevent damage to the system or to customer loads—rather like the "low fuel" or "high engine temperature" warnings in a car.

When FE's alarm system failed on August 14, its operators were running a complex power system without adequate indicators of when key elements of that system were reaching and passing the limits of safe operation—and without awareness that they were running the system without these alarms and should no longer trust the fact that they were not getting alarms as indicating that system conditions were still safe and not changing.

application and all other EMS software running on the first server automatically transferred ("failed-over") onto the back-up server. However, because the alarm application moved intact onto the backup while still stalled and ineffective, the backup server failed 13 minutes later, at 14:54 EDT. Accordingly, all of the EMS applications on these two servers stopped running.

The concurrent loss of both EMS servers apparently caused several new problems for FE's EMS and the operators who used it. Tests run during FE's after-the-fact analysis of the alarm failure event indicate that a concurrent absence of these servers can significantly slow down the rate at which the EMS system puts new—or refreshes existing—displays on operators' computer consoles. Thus at times on August 14th, operators' screen refresh rates—the rate at which new information and displays are painted onto the computer screen, normally 1 to 3 seconds—slowed to as long as 59 seconds per screen. Since FE operators have numerous information screen options, and one or more screens are commonly "nested" as sub-screens to one or more top level screens, operators' ability to view, understand and operate their system through the EMS would have slowed to a frustrating crawl.[13] This situation may have occurred between 14:54 EDT and 15:08 EDT when both servers failed, and again between 15:46 EDT and 15:59 EDT while FE's IT personnel attempted to reboot both servers to remedy the alarm problem.

Loss of the first server caused an auto-page to be issued to alert FE's EMS IT support personnel to the problem. When the back-up server failed, it too sent an auto-page to FE's IT staff. At 15:08 EDT, IT staffers completed a "warm reboot" (restart) of the primary server. Startup diagnostics monitored during that reboot verified that the computer and all expected processes were running; accordingly, FE's IT staff believed that they had successfully restarted the node and all the processes it was hosting. However, although the server and its applications were again running, the alarm system remained frozen and non-functional, even on the restarted computer. The IT staff did not confirm that the alarm system was again working properly with the control room operators.

Another casualty of the loss of both servers was the Automatic Generation Control (AGC) function hosted on those computers. Loss of AGC meant that FE's operators could not run affiliated power plants on pre-set programs to respond automatically to meet FE's system load and interchange obligations. Although the AGC did not work from 14:54 EDT to 15:08 EDT and 15:46 EDT to 15:59 EDT (periods when both servers were down), this loss of function does not appear to have had any effect on the blackout.

The concurrent loss of the EMS servers also caused the failure of FE's strip chart function. There are many strip charts in the FE Reliability Operator control room driven by the EMS computers, showing a variety of system conditions, including raw ACE (Area Control Error), FE System Load, and Sammis-South Canton and South Canton-Star loading. These charts are visible in the reliability operator control room. The chart printers continued to scroll but because the underlying computer system was locked up the chart pens showed only the last valid measurement recorded, without any variation from that measurement as time progressed; i.e. the charts "flat-lined." There is no indication that any operators noticed or reported the failed operation of the charts.[14] The few charts fed by direct analog telemetry, rather than the EMS system, showed primarily frequency data, and remained available throughout the afternoon of August 14. These yield little useful system information for operational purposes.

FE's Area Control Error (ACE), the primary control signal used to adjust generators and imports to match load obligations, did not function between 14:54 EDT and 15:08 EDT and later between 15:46 EDT and 15:59 EDT, when the two servers were down. This meant that generators were not controlled during these periods to meet FE's load and interchange obligations (except from 15:00 EDT to 15:09 EDT when control was switched to a backup controller). There were no apparent negative impacts due to this failure. It has not been established how loss of the primary generation control signal was identified or if any discussions occurred with respect to the computer system's operational status.[15]

EMS System History. The EMS in service at FE's Ohio control center is a GE Harris (now GE Network Systems) XA21 system. It was initially brought into service in 1995. Other than the application of minor software fixes or patches typically encountered in the ongoing maintenance and support of such a system, the last major updates or revisions to this EMS were implemented in 1998. On August 14 the system was not running the most current release of the XA21 software. FE had decided well before August 14 to replace it with one from another vendor.

FE personnel told the investigation team that the alarm processing application had failed on occasions prior to August 14, leading to loss of the alarming of system conditions and events for FE's operators.[16] However, FE said that the mode and behavior of this particular failure event were both first time occurrences and ones which, at the time, FE's IT personnel neither recognized nor knew how to correct. FE staff told investigators that it was only during a post-outage support call with GE late on 14 August that FE and GE determined that the only available course of action to correct the alarm problem was a "cold reboot"[17] of FE's overall XA21 system. In interviews immediately after the blackout, FE IT personnel indicated that they discussed a cold reboot of the XA21 system with control room operators after they were told of the alarm problem at 15:42 EDT, but decided not to take such action because operators considered power system conditions precarious, were concerned about the length of time that the reboot might take to complete, and understood that a cold boot would leave them with even less EMS support until it was completed.[18]

Clues to the EMS Problems. There is an entry in FE's western desk operator's log at 14:14 EDT referring to the loss of alarms, but it is not clear whether that entry was made at that time or subsequently, referring back to the last known alarm. There is no indication that the operator mentioned the problem to other control room staff and supervisors or to FE's IT staff.

The first clear hint to FE control room staff of any computer problems occurred at 14:19 EDT when a caller and an FE control room operator discussed the fact that three sub-transmission center dial-ups had failed.[19] At 14:25 EDT, a control room operator talked with a caller about the failure of these three remote terminals.[20] The next

Who Saw What?

What data and tools did others have to monitor the conditions on the FE system?

Midwest ISO (MISO), reliability coordinator for FE

Alarms: MISO received indications of breaker trips in FE that registered in their alarms. These alarms were missed. These alarms require a look-up to link the flagged breaker with the associated line or equipment and unless this line was specifically monitored, require another look-up to link the line to the monitored flowgate. MISO operators did not have the capability to click on the on-screen alarm indicator to display the underlying information.

Real Time Contingency Analysis (RTCA): The contingency analysis showed several hundred violations around 15:00 EDT. This included some FE violations, which MISO (FE's reliability coordinator) operators discussed with PJM (AEP's Reliability Coordinator).[a] Simulations developed for this investigation show that violations for a contingency would have occurred after the Harding-Chamberlin trip at 15:05 EDT. There is no indication that MISO addressed this issue. It is not known whether MISO identified the developing Sammis-Star problem.

Flowgate Monitoring Tool: While an inaccuracy has been identified with regard to this tool it still functioned with reasonable accuracy and prompted MISO to call FE to discuss the Hanna-Juniper line problem. It would not have identified problems south of Star since that was not part of the flowgate and thus not modeled in MISO's flowgate monitor.

AEP

Contingency Analysis: According to interviews,[b] AEP had contingency analysis that covered lines into Star. The AEP operator identified a problem for Star-South Canton overloads for a Sammis-Star line loss about 15:33 EDT and asked PJM to develop TLRs for this.

Alarms: Since a number of lines cross between AEP's and FE's systems, they had the ability at their respective end of each line to identify contingencies that would affect both. AEP initially noticed FE line problems with the first and subsequent trippings of the Star-South Canton 345-kV line, and called FE three times between 14:35 EDT and 15:45 EDT to determine whether FE knew the cause of the outage.[c]

[a] "MISO Site Visit," Benbow interview.
[b] "AEP Site Visit," Ulrich interview.
[c] Example at 14:35, Channel 4; 15:19, Channel 4; 15:45, Channel 14 (FE transcripts).

hint came at 14:32 EDT, when FE scheduling staff spoke about having made schedule changes to update the EMS pages, but that the totals did not update.[21]

Although FE's IT staff would have been aware that concurrent loss of its servers would mean the loss of alarm processing on the EMS, the investigation team has found no indication that the IT staff informed the control room staff either when they began work on the servers at 14:54 EDT, or when they completed the primary server restart at 15:08 EDT. At 15:42 EDT, the IT staff were first told of the alarm problem by a control room operator; FE has stated to investigators that their IT staff had been unaware before then that the alarm processing sub-system of the EMS was not working.

Cause 1: Inadequate Situational Awareness

Without the EMS systems, the only remaining ways to monitor system conditions would have been through telephone calls and direct analog telemetry. FE control room personnel did not realize that alarm processing on their EMS was not working and, subsequently, did not monitor other available telemetry.

Cause 1: Inadequate Situational Awareness

During the afternoon of August 14, FE operators talked to their field personnel, MISO, PJM (concerning an adjoining system in PJM's reliability coordination region), adjoining systems (such as AEP), and customers. The FE operators received pertinent information from all these sources, but did not grasp some key information about the system from the clues offered. This pertinent information included calls such as that from FE's eastern control center where they were asking about possible line trips, FE Perry nuclear plant calls regarding what looked like near-line trips, AEP calling about their end of the Star-South Canton line tripping, and MISO and PJM calling about possible line overloads.

Without a functioning alarm system, the FE control area operators failed to detect the tripping of electrical facilities essential to maintain the security of their control area. Unaware of the loss of alarms and a limited EMS, they made no alternate arrangements to monitor the system. When AEP identified a circuit trip and reclosure on a 345-kV line, the FE operator dismissed the information as either not accurate or not relevant to his system, without following up on the discrepancy between the AEP event and the information from his own tools. There was no subsequent verification of conditions with their MISO reliability coordinator. Only after AEP notified FE that a 345-kV circuit had tripped and locked out did the FE control area operator compare this information to the breaker statuses for their station. FE failed to inform immediately its reliability coordinator and adjacent control areas when they became aware that system conditions had changed due to unscheduled equipment outages that might affect other control areas.

Phase 3: Three FE 345-kV Transmission Line Failures and Many Phone Calls: 15:05 EDT to 15:57 EDT

Overview of This Phase

From 15:05:41 EDT to 15:41:35 EDT, three 345-kV lines failed with power flows at or below each transmission line's emergency rating. Each was the result of a contact between a line and a tree that had grown so tall that, over a period of years, it encroached into the required clearance height for the line. As each line failed, its outage increased the loading on the remaining lines (Figure 4.5). As each of the transmission lines failed, and power flows shifted to other transmission paths, voltages on the rest of FE's system degraded further (Figure 4.6).

Key Phase 3 Events

3A) 15:05:41 EDT: Harding-Chamberlin 345-kV line tripped.

3B) 15:31-33 EDT: MISO called PJM to determine if PJM had seen the Stuart-Atlanta 345-kV line outage. PJM confirmed Stuart-Atlanta was out.

Figure 4.5. FirstEnergy 345-kV Line Flows

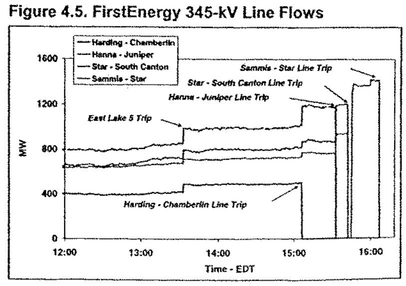
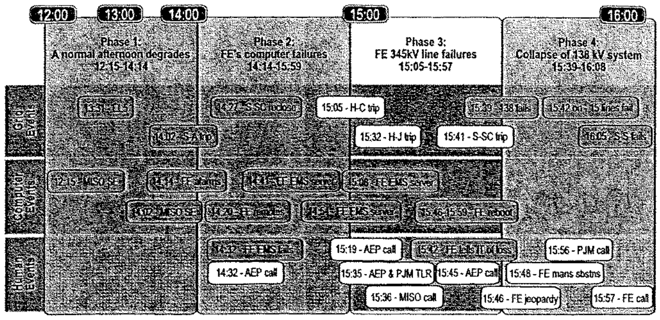


Figure 4.7. Timeline Phase 3



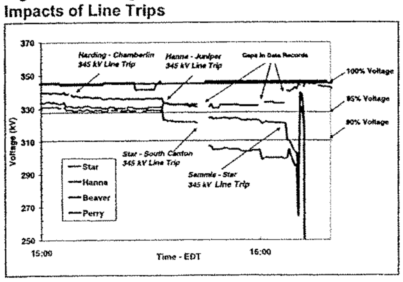
3C) 15:32:03 EDT: Hanna-Juniper 345-kV line tripped.

3D) 15:35 EDT: AEP asked PJM to begin work on a 350-MW TLR to relieve overloading on the Star-South Canton line, not knowing the Hanna-Juniper 345-kV line had already tripped at 15:32 EDT.

3E) 15:36 EDT: MISO called FE regarding post-contingency overload on Star-Juniper 345-kV line for the contingency loss of the Hanna-Juniper 345-kV line, unaware at the start of the call that Hanna-Juniper had already tripped.

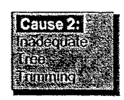
3F) 15:41:33-41 EDT: Star-South Canton 345-kV tripped, reclosed, tripped again at 15:41 EDT and remained out of service, all while AEP and PJM were discussing TLR relief options (event 3D).

Figure 4.6. Voltages on FirstEnergy's 345-kV Lines: Impacts of Line Trips



Transmission lines are designed with the expectation that they will sag lower when they are hotter. The transmission line gets hotter with heavier line loading and under higher ambient temperatures, so towers and conductors are designed to be tall enough and conductors pulled tightly enough to accommodate expected sagging.

A short-circuit occurred on the Harding-Chamberlin 345-kV line due to a contact between the line conductor and a tree. This line failed with power flow at only 43.5% of its normal and emergency line rating. Incremental line current and temperature increases, escalated by the loss of Harding-Chamberlin, caused enough sag on the Hanna-Juniper line that it contacted a tree and faulted with power flow at 87.5% of its normal and emergency line rating. Star-South Canton contacted a tree three times between 14:27:15 EDT and 15:41:33 EDT, opening and reclosing each time before finally locking out while loaded at 93.2% of its emergency rating at 15:42:35 EDT.



Overgrown trees, as opposed to excessive conductor sag, caused each of these faults. While sag may have contributed to these events, these incidents occurred because the trees grew too tall and encroached into the space below the line which is intended to be clear of any objects, not because the lines sagged into short trees. Because the trees were so tall (as discussed below), each of these lines faulted under system conditions well within specified operating parameters. The investigation team found field evidence of tree contact at all three locations, although Hanna-Juniper is the only one with a confirmed sighting for the August 14

Line Ratings

A conductor's normal rating reflects how heavily the line can be loaded under routine operation and keep its internal temperature below 90°C. A conductor's emergency rating is often set to allow higher-than-normal power flows, but to limit its internal temperature to a maximum of 100°C for no longer than a short, specified period, so that it does not sag too low. For three of the four 345-kV lines that failed, FE set the normal and emergency ratings at the same level.

tree/line contact. For the other locations, the team found various types of evidence, outlined below, that confirm that contact with trees caused the short circuits to ground that caused each line to trip out on August 14.

To be sure that the evidence of tree/line contacts and tree remains found at each site was linked to the events of August 14, the team looked at whether these lines had any prior history of outages in preceding months or years that might have resulted in the burn marks, debarking, and other vegetative evidence of line contacts. The record establishes that there were no prior sustained outages known to be caused by trees for these lines in 2001, 2002 and 2003.[22]

Like most transmission owners, FE patrols its lines regularly, flying over each transmission line twice a year to check on the condition of the rights-of-way. Notes from fly-overs in 2001 and 2002 indicate that the examiners saw a significant number of trees and brush that needed clearing or trimming along many FE transmission lines.

Utility Vegetation Management: When Trees and Lines Contact

Vegetation management is critical to any utility company that maintains overhead energized lines. It is important and relevant to the August 14 events because electric power outages occur when trees, or portions of trees, grow up or fall into overhead electric power lines. While not all outages can be prevented (due to storms, heavy winds, etc.), many outages can be mitigated or prevented by managing the vegetation *before* it becomes a problem. When a tree contacts a power line it causes a short circuit, which is read by the line's relays as a ground fault. Direct physical contact is not necessary for a short circuit to occur. An electric arc can occur between a part of a tree and a nearby high-voltage conductor if a sufficient distance separating them is not maintained. Arcing distances vary based on such factors such as voltage and ambient wind and temperature conditions. Arcs can cause fires as well as short circuits and line outages.

Most utilities have right-of-way and easement agreements allowing the utility to clear and maintain the vegetation as needed along its lines to provide safe and reliable electric power. Easements give the utility a great deal of control over the landscape, with extensive rights to do whatever work is required to maintain the lines with adequate clearance through the control of vegetation. The three principal means of managing vegetation along a transmission right-of-way are pruning the limbs adjacent to the line clearance zone, removing vegetation completely by mowing or cutting, and using herbicides to retard or kill further growth. It is common to see more tree and brush removal using mechanical and chemical tools and relatively less pruning along transmission rights-of-way.

FE's easement agreements establish extensive rights regarding what can be pruned or removed in these transmission rights-of-way, including: "the right to erect, inspect, operate, replace, relocate, repair, patrol and permanently maintain upon, over, under and along the above described right of way across said premises all necessary structures, wires, cables and other usual fixtures and appurtenances used for or in connection with the transmission and distribution of electric current, including telephone and telegraph, and the right to trim, cut, remove or control by any other means at any and all times such trees, limbs and underbrush within or adjacent to said right of way as may interfere with or endanger said structures, wires or appurtenances, or their operations."[a]

FE uses a 5-year cycle for transmission line vegetation maintenance, i.e. completes all required vegetation work within a five year period for all circuits. A 5-year cycle is consistent with industry standards, and it is common for transmission providers not to fully exercise their easement rights on transmission rights-of-way due to landowner opposition.

[a]Standard language in FE's right-of-way easement agreement.

3A) FE's Harding-Chamberlin 345-kV Line Tripped: 15:05 EDT

Cause 2: Inadequate Tree Trimming

At 15:05:41 EDT, FE's Harding-Chamberlin line (Figure 4.8) tripped and locked out while loaded at 43.5% of its normal and emergency rating. The investigation team has examined the relay data for this trip, identified the geographic location of the fault, and determined that the relay data match the classic "signature" pattern for a tree/line short circuit to ground fault. Going to the fault location determined from the relay data, the field team found the remains of trees and brush. At this location, conductor height measured 46 feet 7 inches, while the height of the felled tree measured 42 feet; however, portions of the tree had been removed from the site. This means that while it is difficult to determine the exact height of the line contact, the measured height is a minimum and the actual contact was likely 3 to 4 feet higher than estimated here. Burn marks were observed 35 feet 8 inches up the tree, and the crown of this tree was at least 6 feet taller than the observed burn marks. The tree showed evidence of fault current damage.[23]

When the Harding-Chamberlin line locked out, the loss of this 345-kV path caused the remaining three southern 345-kV lines into Cleveland to pick up more load, with Hanna-Juniper picking up the most. The Harding-Chamberlin outage also caused more power to flow through the underlying 138-kV system.

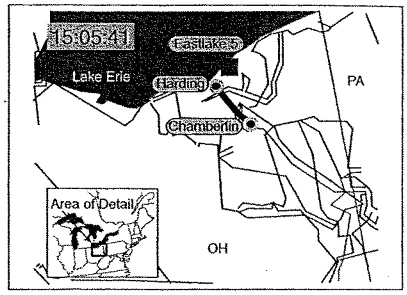
Cause 1: Inadequate Situational Awareness

MISO did not discover that Harding-Chamberlin had tripped until after the blackout, when MISO reviewed the breaker operation log that evening. FE indicates that it discovered the line was out while investigating system conditions in response MISO's call at 15:36 EDT, when MISO told FE that MISO's flowgate monitoring tool showed a Star-Juniper line overload following a contingency loss of Hanna-Juniper;[24] however, the investigation team has found no evidence within the control room logs or transcripts to show that FE knew of the Harding-Chamberlin line failure until after the blackout.

Cause 3: Inadequate RC Diagnostic Support

Harding-Chamberlin was not one of the flowgates that MISO monitored as a key transmission location, so the reliability coordinator was unaware when FE's first 345-kV line failed. Although MISO received SCADA input of the line's status change, this was presented to MISO operators as breaker status changes rather than a line failure. Because their EMS system topology processor had not yet been linked to recognize line failures, it did not connect the breaker information to the loss of a transmission line. Thus, MISO's operators did not recognize the Harding-Chamberlin trip as a significant contingency event and could not advise FE regarding the event or its consequences. Further, without its state estimator and associated contingency analyses, MISO was unable to identify potential overloads that would occur due to various line or equipment outages. Accordingly, when the Harding-Chamberlin 345-kV line tripped at 15:05 EDT, the state estimator did not produce results and could not predict an overload if the Hanna-Juniper 345-kV line were to fail.[25]

Figure 4.8. Harding-Chamberlin 345-kV Line



3C) FE's Hanna-Juniper 345-kV Line Tripped: 15:32 EDT

Cause 2: Inadequate Tree Trimming

At 15:32:03 EDT the Hanna-Juniper line (Figure 4.9) tripped and locked out. A tree-trimming crew was working nearby and observed the tree/line contact. The tree contact occurred on the South phase, which is lower than the center phase due to construction design. Although little evidence remained of the tree during the field team's visit in October, the team observed a tree stump 14 inches in diameter at its ground line and talked to an individual who witnessed the contact on August 14.[26] FE provided photographs that clearly indicate that the tree was of excessive height. Surrounding trees were 18 inches in diameter at ground line and 60 feet in height (not near lines). Other sites at this location had numerous (at least 20) trees in this right-of-way.

Figure 4.9. Hanna-Juniper 345-kV Line

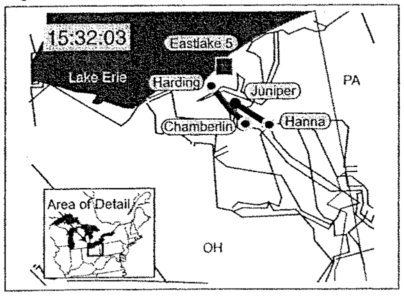
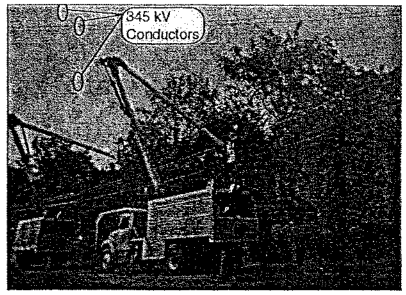


Figure 4.10. Cause of the Hanna-Juniper Line Loss



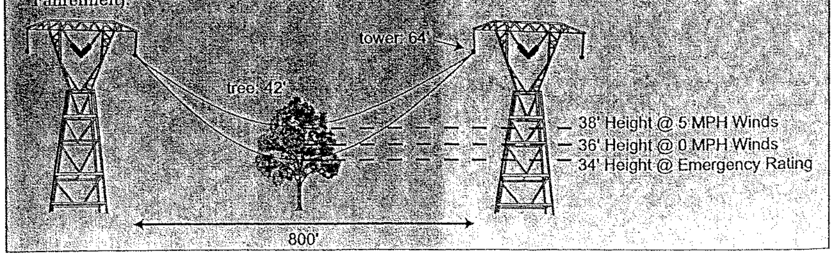
This August 14 photo shows the tree that caused the loss of the Hanna-Juniper line (tallest tree in photo). Other 345-kV conductors and shield wires can be seen in the background. Photo by Nelson Tree.

Why Did So Many Tree-to-Line Contacts Happen on August 14?

Tree-to-line contacts and resulting transmission outages are not unusual in the summer across much of North America. The phenomenon occurs because of a combination of events occurring particularly in late summer:

- Most tree growth occurs during the spring and summer months, so the later in the summer the taller the tree and the greater its potential to contact a nearby transmission line.
- As temperatures increase, customers use more air conditioning and load levels increase. Higher load levels increase flows on the transmission system, causing greater demands for both active power (MW) and reactive power (MVAr). Higher flow on a transmission line causes the line to heat up, and the hot line sags lower because the hot conductor metal expands. Most emergency line ratings are set to limit conductors' internal temperatures to no more than 100 degrees Celsius (212 degrees Fahrenheit).
- As temperatures increase, ambient air temperatures provide less cooling for loaded transmission lines.
- Wind flows cool transmission lines by increasing the airflow of moving air across the line. On August 14 wind speeds at the Ohio Akron-Fulton airport averaged 5 knots at around 14:00 EDT, but by 15:00 EDT wind speeds had fallen to 2 knots (the wind speed commonly assumed in conductor design) or lower. With lower winds, the lines sagged further and closer to any tree limbs near the lines.

This combination of events on August 14 across much of Ohio and Indiana caused transmission lines to heat and sag. If a tree had grown into a power line's designed clearance area, then a tree/line contact was more likely, though not inevitable. An outage on one line would increase power flows on related lines, causing them to be loaded higher, heat further, and sag lower.



Hanna-Juniper was loaded at 87.5% of its normal and emergency rating when it tripped. With this line open, almost 1,000 MVA had to find a new path to reach its load in Cleveland. Loading on the remaining two 345-kV lines increased, with Star-Juniper taking the bulk of the power. This caused Star-South Canton's loading to rise above its normal but within its emergency rating and pushed more power onto the 138-kV system. Flows west into Michigan decreased slightly and voltages declined somewhat in the Cleveland area.

3D) AEP and PJM Begin Arranging a TLR for Star-South Canton: 15:35 EDT

Cause 3: Inadequate RC Diagnostic Support

Because its alarm system was not working, FE was not aware of the Harding-Chamberlin or Hanna-Juniper line trips. However, once MISO manually updated the state estimator model for the Stuart-Atlanta 345-kV line outage, the software successfully completed a state estimation and contingency analysis at 15:41 EDT. But this left a 36 minute period, from 15:05 EDT to 15:41 EDT, during which MISO did not recognize the consequences of the Hanna-Juniper loss, and FE operators knew neither of the line's loss nor its consequences. PJM and AEP recognized the overload on Star-South Canton, but had not expected it because their earlier contingency analysis did not examine enough lines within the FE system to foresee this result of the Hanna-Juniper contingency on top of the Harding-Chamberlin outage.

Cause 3: Inadequate RC Diagnostic Support

After AEP recognized the Star-South Canton overload, at 15:35 EDT AEP asked PJM to begin developing a 350-MW TLR to mitigate it. The TLR was to relieve the actual overload above normal rating then occurring on Star-South Canton, and prevent an overload above emergency rating on that line if the Sammis-Star line were to fail. But when they began working on the TLR, neither AEP nor PJM realized that the Hanna-Juniper 345-kV line had

Handling Emergencies by Shedding Load and Arranging TLRs

Transmission loading problems. Problems such as contingent overloads or contingent breaches of stability limits are typically handled by arranging Transmission Loading Relief (TLR) measures, which in most cases take effect as a schedule change 30 to 60 minutes after they are issued. Apart from a TLR level 6, TLRs are intended as a tool to prevent the system from being operated in an unreliable state,[a] and are not applicable in real-time emergency situations because it takes too long to implement reductions. Actual overloads and violations of stability limits need to be handled immediately under TLR level 6 by redispatching generation, system reconfiguration or tripping load. The dispatchers at FE, MISO and other control areas or reliability coordinators have authority—and under NERC operating policies, responsibility—to take such action, but the occasion to do so is relatively rare.

Lesser TLRs reduce scheduled transactions—non-firm first, then pro-rata between firm transactions, including native load. When pre-contingent conditions are not solved with TLR levels 3 and 5, or conditions reach actual overloading or surpass stability limits, operators must use emergency generation redispatch and/or load-shedding under TLR level 6 to return to a secure state. After a secure state is reached, TLR level 3 and/or 5 can be initiated to relieve the emergency generation redispatch or load-shedding activation.

System operators and reliability coordinators, by NERC policy, have the responsibility and the authority to take actions up to and including emergency generation redispatch and shedding firm load to preserve system security. On August 14, because they either did not know or understand enough about system conditions at the time, system operators at FE, MISO, PJM, or AEP did not call for emergency actions.

Use of automatic procedures in voltage-related emergencies. There are few automatic safety nets in place in northern Ohio except for under-frequency load-shedding in some locations. In some utility systems in the U.S. Northeast, Ontario, and parts of the Western Interconnection, special protection systems or remedial action schemes, such as under-voltage load-shedding are used to shed load under defined severe contingency conditions similar to those that occurred in northern Ohio on August 14.

[a] "Northern MAPP/Northwestern Ontario Disturbance-June 25, 1998," NERC 1998 Disturbance Report, page 17.

already tripped at 15:32 EDT, further degrading system conditions. Since the great majority of TLRs are for cuts of 25 to 50 MW, a 350-MW TLR request was highly unusual and operators were attempting to confirm why so much relief was suddenly required before implementing the requested TLR. Less than ten minutes elapsed between the loss of Hanna-Juniper, the overload above the normal limits of Star-South Canton, and the Star-South Canton trip and lock-out.

Cause 3: Inadequate RC Diagnostic Support

The primary tool MISO uses for assessing reliability on key flowgates (specified groupings of transmission lines or equipment that sometimes have less transfer capability than desired) is the flowgate monitoring tool. After the Harding-Chamberlin 345-kV line outage at 15:05 EDT, the flowgate monitoring tool produced incorrect (obsolete) results, because the outage was not reflected in the model. As a result, the tool assumed that Harding-Chamberlin was still available and did not predict an overload for loss of the Hanna-Juniper 345-kV line. When Hanna-Juniper tripped at 15:32 EDT, the resulting overload was detected by MISO's SCADA and set off alarms to MISO's system operators, who then phoned FE about it.[27] Because both MISO's state estimator, which was still in a developmental state, and its flowgate monitoring tool were not working properly, MISO's ability to recognize FE's evolving contingency situation was impaired.

3F) Loss of the Star-South Canton 345-kV Line: 15:41 EDT

The Star-South Canton line (Figure 4.11) crosses the boundary between FE and AEP, and the line is jointly owned—each company owns the portion of the line within its respective territory and manages the right-of-way there. The Star-South Canton line tripped and reclosed three times on the afternoon of August 14, first at 14:27:15 EDT (reclosing at both ends), then at 15:38:48 EDT, and at 15:41:35 EDT it tripped and locked out at the Star substation. A short-circuit to ground occurred in each case. This line failed with power flow at 93.2% of its emergency rating.

Cause 2: Inadequate Tree Trimming

The investigation field team inspected the right of way in the location indicated by the relay digital fault recorders, in the FE portion of the line. They found debris from trees and vegetation that had been felled. At this location the conductor height was 44 feet 9 inches. The identifiable tree remains measured 30 feet in height, although the team could not verify the location of the stump, nor find all sections of the tree. A nearby cluster of trees showed significant fault damage, including charred limbs and de-barking from fault current. Further, topsoil in the area of the tree trunk was disturbed, discolored and broken up, a common indication of a higher magnitude fault or multiple faults. Analysis of another stump showed that a fourteen year-old tree had recently been removed from the middle of the right-of-way.[28]

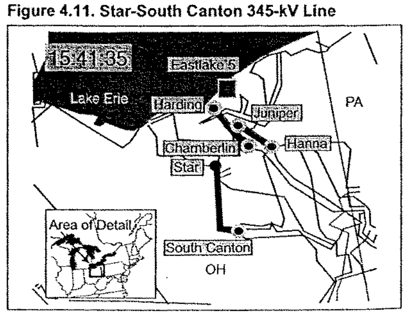
After the Star-South Canton line was lost, flows increased greatly on the 138-kV system toward Cleveland and area voltage levels began to degrade on the 138-kV and 69-kV system. At the same time, power flows increased on the Sammis-Star 345-kV line due to the 138-kV line trips—the only remaining paths into Cleveland from the south.

Cause 1: Inadequate Situational Awareness

FE's operators were not aware that the system was operating outside first contingency limits after the Harding-Chamberlin trip (for the possible loss of Hanna-Juniper), because they did not conduct a contingency analysis.[29] The investigation team has not determined whether the system status information used by FE's state estimator and contingency analysis model was being accurately updated.

System impacts of the 345-kV failures. The investigation modeling team examined the impact of the loss of the Harding-Chamberlin, Hanna-Juniper and Star-South Canton 345-kV lines. After conducting a variety of scenario analyses, they concluded that had either Hanna-Juniper or Harding-Chamberlin been restored and remained in-service, the Star-South Canton line might not have tripped and locked out at 15:42 EDT.

Figure 4.11. Star-South Canton 345-kV Line

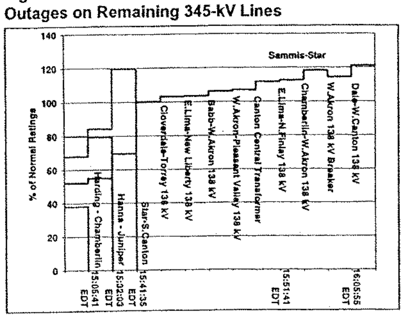


According to extensive investigation team modeling, there were no contingency limit violations as of 15:05 EDT prior to the loss of the Chamberlin-Harding 345-kV line. Figure 4.12 shows the line loadings estimated by investigation team modeling as the 345-kV lines in northeast Ohio began to trip. Showing line loadings on the 345-kV lines as a percent of normal rating, it tracks how the loading on each line increased as each subsequent 345-kV and 138-kV line tripped out of service between 15:05 EDT (Harding-Chamberlin, the first line above to stair-step down) and 16:06 EDT (Dale-West Canton). As the graph shows, none of the 345- or 138-kV lines exceeded their normal ratings until after the combined trips of Harding-Chamberlin and Hanna-Juniper. But immediately after the second line was lost, Star-South Canton's loading jumped from an estimated 82% of normal to 120% of normal (which was still below its emergency rating) and remained at the 120% level for 10 minutes before tripping out. To the right, the graph shows the effects of the 138-kV line failures (discussed in the next phase) upon the two remaining 345-kV lines—i.e., Sammis-Star's loading increased steadily above 100% with each succeeding 138-kV line lost.

Following the loss of the Harding-Chamberlin 345-kV line at 15:05 EDT, contingency limit violations existed for:

- The Star-Juniper 345-kV line, whose loadings would exceed emergency limits if the Hanna-Juniper 345-kV line were lost; and
- The Hanna-Juniper and Harding-Juniper 345-kV lines, whose loadings would exceed emergency limits if the Perry generation unit (1,255 MW) were lost.

Figure 4.12. Cumulative Effects of Sequential Outages on Remaining 345-kV Lines



Operationally, once FE's system entered an N-1 contingency violation state, any facility loss beyond that pushed them farther into violation and into a more unreliable state. After loss of the Harding-Chamberlin line, to avoid violating NERC criteria, FE needed to reduce loading on these three lines within 30 minutes such that no single contingency would violate an emergency limit; that is, to restore the system to a reliable operating mode.

Phone Calls into the FE Control Room

Cause 1: Inadequate Situational Awareness

Beginning no earlier than 14:14 EDT when their EMS alarms failed, and until at least 15:42 EDT when they began to recognize their situation, FE operators did not understand how much of their system was being lost, and did not realize the degree to which their perception of their system was in error versus true system conditions, despite receiving clues via phone calls from AEP, PJM and MISO, and customers. The FE operators were not aware of line outages that occurred after the trip of Eastlake 5 at 13:31 EDT until approximately 15:45 EDT, although they were beginning to get external input describing aspects of the system's weakening condition. Since FE's operators were not aware and did not recognize events as they were occurring, they took no actions to return the system to a reliable state.

A brief description follows of some of the calls FE operators received concerning system problems and their failure to recognize that the problem was on their system. For ease of presentation, this set of calls extends past the time of the 345-kV line trips into the time covered in the next phase, when the 138-kV system collapsed.

Following the first trip of the Star-South Canton 345-kV line at 14:27 EDT, AEP called FE at 14:32 EDT to discuss the trip and reclose of the line. AEP was aware of breaker operations at their end (South Canton) and asked about operations at FE's Star end. FE indicated they had seen nothing at their end of the line but AEP reiterated that the trip occurred at 14:27 EDT and that the South Canton breakers had reclosed successfully.[30] There was an internal FE conversation about the AEP call at 14:51 EDT, expressing concern that they had not seen any indication of an operation, but lacking evidence within their control room, the FE operators did not pursue the issue.

At 15:19 EDT, AEP called FE back to confirm that the Star-South Canton trip had occurred and that

AEP had a confirmed relay operation from the site. FE's operator restated that because they had received no trouble or alarms, they saw no problem. An AEP technician at the South Canton substation verified the trip. At 15:20 EDT, AEP decided to treat the South Canton digital fault recorder and relay target information as a "fluke," and checked the carrier relays to determine what the problem might be.[31]

At 15:35 EDT the FE control center received a call from the Mansfield 2 plant operator concerned about generator fault recorder triggers and excitation voltage spikes with an alarm for over-excitation, and a dispatcher called reporting a "bump" on their system. Soon after this call, FE's Reading, Pennsylvania control center called reporting that fault recorders in the Erie west and south areas had activated, wondering if something had happened in the Ashtabula-Perry area. The Perry nuclear plant operator called to report a "spike" on the unit's main transformer. When he went to look at the metering it was "still bouncing around pretty good. I've got it relay tripped up here ... so I know something ain't right."[32]

Beginning at this time, the FE operators began to think that something was wrong, but did not recognize that it was on their system. "It's got to be in distribution, or something like that, or somebody else's problem ... but I'm not showing anything."[33] Unlike many other transmission grid control rooms, FE's control center does not have a map board (which shows schematically all major lines and plants in the control area on the wall in front of the operators), which might have shown the location of significant line and facility outages within the control area.

At 15:36 EDT, MISO contacted FE regarding the post-contingency overload on Star-Juniper for the loss of the Hanna-Juniper 345-kV line.[34]

At 15:42 EDT, FE's western transmission operator informed FE's IT staff that the EMS system functionality was compromised. "Nothing seems to be updating on the computers.... We've had people calling and reporting trips and nothing seems to be updating in the event summary... I think we've got something seriously sick." This is the first evidence that a member of FE's control room staff recognized any aspect of their degraded EMS system. There is no indication that he informed any of the other operators at this moment. However, FE's IT staff discussed the subsequent EMS alarm corrective action with some control room staff shortly thereafter.

Also at 15:42 EDT, the Perry plant operator called back with more evidence of problems. "I'm still getting a lot of voltage spikes and swings on the generator.... I don't know how much longer we're going to survive."[35]

At 15:45 EDT, the tree trimming crew reported that they had witnessed a tree-caused fault on the Eastlake-Juniper 345-kV line; however, the actual fault was on the Hanna-Juniper 345-kV line in the same vicinity. This information added to the confusion in the FE control room, because the operator had indication of flow on the Eastlake-Juniper line.[36]

After the Star-South Canton 345-kV line tripped a third time and locked out at 15:42 EDT, AEP called FE at 15: 45 EDT to discuss and inform them that they had additional lines that showed overload. FE recognized then that the Star breakers had tripped and remained open.[37]

At 15:46 EDT the Perry plant operator called the FE control room a third time to say that the unit was close to tripping off: "It's not looking good.... We ain't going to be here much longer and you're going to have a bigger problem."[38]

At 15:48 EDT, an FE transmission operator sent staff to man the Star substation, and then at 15:50 EDT, requested staffing at the regions, beginning with Beaver, then East Springfield.[39]

At 15:48 EDT, PJM called MISO to report the Star-South Canton trip, but the two reliability coordinators' measures of the resulting line flows on FE's Sammis-Star 345-kV line did not match, causing them to wonder whether the Star-South Canton 345-kV line had returned to service.[40]

At 15:56 EDT, because PJM was still concerned about the impact of the Star-South Canton trip, PJM called FE to report that Star-South Canton had tripped and that PJM thought FE's Sammis-Star line was in actual emergency limit overload. FE could not confirm this overload. FE informed PJM that Hanna-Juniper was also out service. FE believed that the problems existed beyond their system. "AEP must have lost some major stuff."[41]

Emergency Action

For FirstEnergy, as with many utilities, emergency awareness is often focused on energy shortages. Utilities have plans to reduce loads under these circumstances to increasingly greater degrees. Tools include calling for contracted customer load reductions, then public appeals, voltage reductions, and finally shedding system load by cutting off interruptible and firm customers. FE has a plan for this that is updated yearly. While they can trip loads quickly where there is SCADA control of load breakers (although FE has few of these), from an energy point of view, the intent is to be able to regularly rotate what loads are not being served, which requires calling personnel out to switch the various groupings in and out. This event was not, however, a capacity or energy emergency or system instability, but an emergency due to transmission line overloads.

To handle an emergency effectively a dispatcher must first identify the emergency situation and then determine effective action. AEP identified potential contingency overloads at 15:36 EDT and called PJM even as Star-South Canton, one of the AEP/FE lines they were discussing, tripped and pushed FE's Sammis-Star 345-kV line to its emergency rating. Since that event was the opposite of the focus of their discussion about a TLR for a possible loss of Sammis-Star that would overload Star-South Canton, they recognized that a serious problem had arisen on the system for which they did not have a ready solution.[42] Later, around 15:50 EDT, their conversation reflected emergency conditions (138-kV lines were tripping and several other lines overloaded) but they still found no practical way to mitigate these overloads across utility and reliability coordinator boundaries.

At the control area level, FE remained unaware of the precarious condition their system was in, with key lines out of service, degrading voltages, and severe overloads on their remaining lines.[43] Transcripts show that FE operators were aware of falling voltages and customer problems after loss of the Hanna-Juniper 345-kV line (at 15:32 EDT). They called out personnel to staff substations because they did not think they could see them with their data gathering tools. They were also talking to customers. But there is no indication that FE's operators clearly identified their situation as a possible emergency until around 15:45 EDT when the shift supervisor informed his manager that it looked as if they were losing the system; even then, although FE had grasped that its system was in trouble, it never officially declared that it was an emergency condition and that emergency or extraordinary action was needed.

FE's internal control room procedures and protocols did not prepare them adequately to identify and react to the August 14 emergency. Throughout the afternoon of August 14 there were many clues that FE had lost both its critical monitoring alarm functionality and that its transmission system's reliability was becoming progressively more compromised. However, FE did not fully piece these clues together until after it had already lost critical elements of its transmission system and only minutes before subsequent trippings triggered the cascade phase of the blackout. The clues to a compromised EMS alarm system and transmission system came from a number of reports from various parties external to the FE transmission control room. Calls from FE customers, generators, AEP, MISO and PJM came into the FE control room. In spite of these clues, because of a number of related factors, FE failed to identify the emergency that it faced.

The most critical factor delaying the assessment and synthesis of the clues was a lack of information sharing between the FE system operators. In interviews with the FE operators and analysis of phone transcripts, it is evident that rarely were any of the critical clues shared with fellow operators. This lack of information sharing can be attributed to:

1. Physical separation of operators (the reliability operator responsible for voltage schedules is across the hall from the transmission operators).
2. The lack of a shared electronic log (visible to all), as compared to FE's practice of separate hand-written logs.[44]
3. Lack of systematic procedures to brief incoming staff at shift change times.
4. Infrequent training of operators in emergency scenarios, identification and resolution of bad data, and the importance of sharing key information throughout the control room.

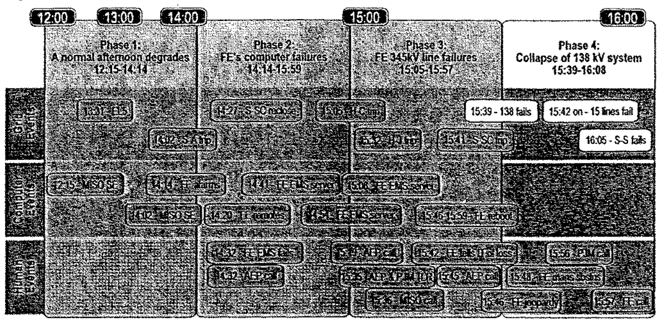
Cause 1: Inadequate Situational Awareness

FE has specific written procedures and plans for dealing with resource deficiencies, voltage depressions, and overloads, and these include instructions to adjust generators and trip firm loads. After the loss of the Star-South Canton line, voltages were below limits, and there were severe line overloads. But FE did not follow any of these procedures on August 14, because FE did not know for most of that time that its system might need such treatment.

Cause 3: Inadequate RC Diagnostic Support

MISO was hindered because it lacked clear visibility, responsibility, authority, and ability to take the actions needed in this circumstance. MISO had interpretive and operational tools and a large amount of

Figure 4.13. Timeline Phase 4



system data, but had a limited view of FE's system. In MISO's function as FE's reliability coordinator, its primary task was to initiate and implement TLRs, recognize and solve congestion problems in less dramatic reliability circumstances with longer solution time periods than those which existed on August 14.

What training did the operators and reliability coordinators have for recognizing and responding to emergencies? FE relied upon on-the-job experience as training for its operators in handling the routine business of a normal day but had never experienced a major disturbance and had no simulator training or formal preparation for recognizing and responding to emergencies. Although all affected FE and MISO operators were NERC certified, neither group had significant training, documentation, or actual experience for how to handle an emergency of this type and magnitude.

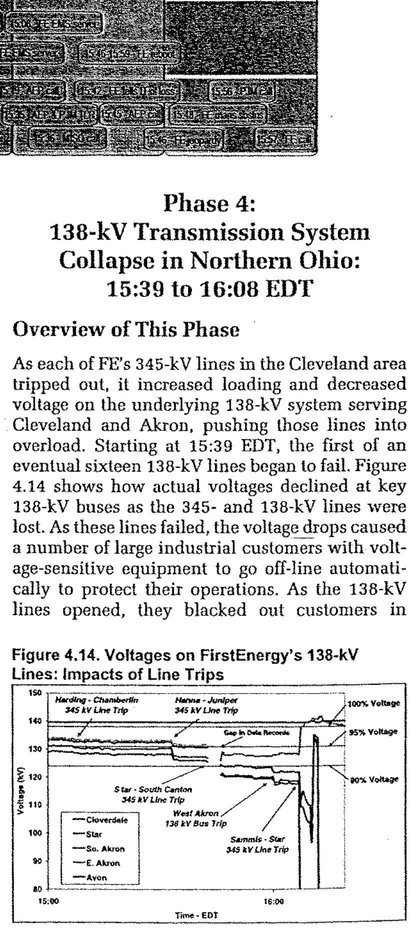
Throughout August 14, most major elements of FE's EMS were working properly. The system was automatically transferring accurate real-time information about FE's system conditions to computers at AEP, MISO, and PJM. FE's operator did not believe the transmission line failures reported by AEP and MISO were real until 15:42 EDT, after FE conversations with the AEP and MISO control rooms and calls from FE IT staff to report the failure of their alarms. At that point in time, FE operators began to think that their system might be in jeopardy—but they did not act to restore any of the lost transmission lines, clearly alert their reliability coordinator or neighbors about their situation, or take other possible remedial measures (such as load-shedding) to stabilize their system.

Phase 4: 138-kV Transmission System Collapse in Northern Ohio: 15:39 to 16:08 EDT

Overview of This Phase

As each of FE's 345-kV lines in the Cleveland area tripped out, it increased loading and decreased voltage on the underlying 138-kV system serving Cleveland and Akron, pushing those lines into overload. Starting at 15:39 EDT, the first of an eventual sixteen 138-kV lines began to fail. Figure 4.14 shows how actual voltages declined at key 138-kV buses as the 345- and 138-kV lines were lost. As these lines failed, the voltage drops caused a number of large industrial customers with voltage-sensitive equipment to go off-line automatically to protect their operations. As the 138-kV lines opened, they blacked out customers in

Figure 4.14. Voltages on FirstEnergy's 138-kV Lines: Impacts of Line Trips



Akron and the areas west and south of the city, ultimately dropping about 600 MW of load.

Key Phase 4 Events

Between 15:39 EDT and 15:58:47 EDT seven 138-kV lines tripped:

4A) 15:39:17 EDT: Pleasant Valley-West Akron 138-kV line tripped and reclosed at both ends.
15:42:05 EDT: Pleasant Valley-West Akron 138-kV West line tripped and reclosed.
15:44:40 EDT: Pleasant Valley-West Akron 138-kV West line tripped and locked out.

4B) 15:42:49 EDT: Canton Central-Cloverdale 138-kV line tripped and reclosed.
15:45:39 EDT: Canton Central-Cloverdale 138-kV line tripped and locked out.

4C) 15:42:53 EDT: Cloverdale-Torrey 138-kV line tripped.

4D) 15:44:12 EDT: East Lima-New Liberty 138-kV line tripped.

4E) 15:44:32 EDT: Babb-West Akron 138-kV line and locked out.

4F) 15:51:41 EDT: East Lima-N. Findlay 138-kV line tripped and reclosed at East Lima end only.

4G) 15:58:47 EDT: Chamberlin-West Akron 138-kV line tripped.
Note: 15:51:41 EDT: Fostoria Central-N. Findlay 138-kV line tripped and reclosed, but never locked out.

At 15:59:00 EDT, the loss of the West Akron bus caused another five 138-kV lines to trip:

4H) 15:59:00 EDT: West Akron 138-kV bus tripped, and cleared bus section circuit breakers at West Akron 138 kV.

4I) 15:59:00 EDT: West Akron-Aetna 138-kV line opened.

4J) 15:59:00 EDT: Barberton 138-kV line opened at West Akron end only. West Akron-B18 138-kV tie breaker opened, affecting West Akron 138/12-kV transformers #3, 4 and 5 fed from Barberton.

4K) 15:59:00 EDT: West Akron-Granger-Stoney-Brunswick-West Medina opened.

4L) 15:59:00 EDT: West Akron-Pleasant Valley 138-kV East line (Q-22) opened.

4M) 15:59:00 EDT: West Akron-Rosemont-Pine-Wadsworth 138-kV line opened.

From 16:00 EDT to 16:08:59 EDT, four 138-kV lines tripped, and the Sammis-Star 345-kV line tripped on overload:

4N) 16:05:55 EDT: Dale-West Canton 138-kV line tripped at both ends, reclosed at West Canton only

4O) 16:05:57 EDT: Sammis-Star 345-kV line tripped

4P) 16:06:02 EDT: Star-Urban 138-kV line tripped

4Q) 16:06:09 EDT: Richland-Ridgeville-Napoleon-Stryker 138-kV line tripped and locked out at all terminals

4R) 16:08:58 EDT: Ohio Central-Wooster 138-kV line tripped
Note: 16:08:55 EDT: East Wooster-South Canton 138-kV line tripped, but successful automatic reclosing restored this line.

4A-G) Pleasant Valley to Chamberlin-West Akron Line Outages

From 15:39 EDT to 15:58:47 EDT, seven 138-kV lines in northern Ohio tripped and locked out. At 15:45:41 EDT, Canton Central-Tidd 345-kV line tripped and reclosed at 15:46:29 EDT because Canton Central 345/138-kV CB "A1" operated multiple times, causing a low air pressure problem that inhibited circuit breaker tripping. This event forced the Canton Central 345/138-kV transformers to disconnect and remain out of service, further weakening the Canton-Akron area 138-kV transmission system. At 15:58:47 EDT the Chamberlin-West Akron 138-kV line tripped.

4H-M) West Akron Transformer Circuit Breaker Failure and Line Outages

At 15:59 EDT FE's West Akron 138-kV bus tripped due to a circuit breaker failure on West Akron transformer #1. This caused the five remaining 138-kV lines connected to the West Akron substation to open. The West Akron 138/12-kV transformers remained connected to the Barberton-West Akron 138-kV line, but power flow to West Akron 138/69-kV transformer #1 was interrupted.

4N-O) Dale-West Canton 138-kV and Sammis-Star 345-kV Lines Tripped

After the Cloverdale-Torrey line failed at 15:42 EDT, Dale-West Canton was the most heavily loaded line on FE's system. It held on, although heavily overloaded to 160 and 180% of normal ratings, until tripping at 16:05:55 EDT. The loss of this line had a significant effect on the area, and voltages dropped significantly. More power shifted back to the remaining 345-kV network, pushing Sammis-Star's loading above 120% of rating. Two seconds later, at 16:05:57 EDT, Sammis-Star tripped out. Unlike the previous three 345-kV lines, which tripped on short circuits to ground due to tree contacts, Sammis-Star tripped because its protective relays saw low apparent impedance (depressed voltage divided by abnormally high line current)—i.e., the relay reacted as if the high flow was due to a short circuit. Although three more 138-kV lines dropped quickly in Ohio following the Sammis-Star trip, loss of the Sammis-Star line marked the turning point at which system problems in northeast Ohio initiated a cascading blackout across the northeast United States and Ontario.[45]

Losing the 138-kV System

The tripping of 138-kV transmission lines that began at 15:39 EDT occurred because the loss of the combination of the Harding-Chamberlin, Hanna-Juniper and Star-South Canton 345-kV lines overloaded the 138-kV system with electricity flowing north toward the Akron and Cleveland loads. Modeling indicates that the return of either the Hanna-Juniper or Chamberlin-Harding 345-kV lines would have diminished, but not alleviated, all of the 138-kV overloads. In theory, the return of both lines would have restored all the 138 lines to within their emergency ratings.

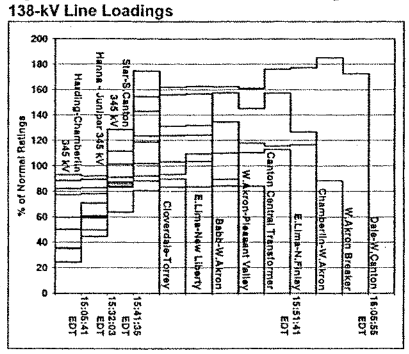
Cause 1: Inadequate Situational Awareness

However, all three 345-kV lines had already been compromised due to tree contacts so it is unlikely that FE would have successfully restored either line had they known it had tripped out, and since Star-South Canton had already tripped and reclosed three times it is also unlikely that an operator knowing this would have trusted it to operate securely under emergency conditions. While generation redispatch scenarios alone would not have solved the overload problem, modeling indicates that shedding load in the Cleveland and Akron areas may have reduced most line loadings to within emergency range and helped stabilize the system. However, the amount of load shedding required grew rapidly as FE's system unraveled.

Loss of the Sammis-Star 345-kV Line

Figure 4.15, derived from investigation team modeling, shows how the power flows shifted across FE's 345- and key 138-kV northeast Ohio lines as the line failures progressed. All lines were loaded within normal limits after the Harding-Chamberlin lock-out, but after the Hanna-Juniper trip at 15:32, the Star-South Canton 345-kV line and three 138-kV lines jumped above normal loadings. After Star-South Canton locked out at 15:41 EDT, five 138-kV and the Sammis-Star 345-kV lines were overloaded and Star-South Canton was within its emergency rating. From that point, as the graph shows, each subsequent line loss increased loadings on other lines, some loading to well over 150% of normal ratings before they failed. The Sammis-Star 345-kV line stayed in service until it tripped at 16:05:57 EDT.

Figure 4.15. Simulated Effect of Prior Outages on 138-kV Line Loadings



Endnotes

[1]*August 14, 2003 Outage Sequence of Events*, U.S./Canada Power Outage Task Force (September 12, 2003), http://www.electricity.doe.gov/documents/1282003113351_BlackoutSummary.pdf.

[2]DOE Site Visit to FE 10/8/2003: Steve Morgan.

[3]DOE Site Visit to FE, September 3, 2003, Hough interview: "When asked whether the voltages seemed unusual, he said that some sagging would be expected on a hot day, but on August 14th the voltages did seem unusually low." Spidle interview: "The voltages for the day were not particularly bad."

[4]Manual of Operations, valid as of March 3, 2003, Process flowcharts: Voltage Control and Reactive Support – Plant and System Voltage Monitoring Under Normal Conditions.

[5]14:13:18. Channel 16 - Sammis 1. 13:15:49 / Channel 16 – West Lorain (FE Reliability Operator (RO) says, "Thanks. We're starting to sag all over the system.") / 13:16:44. Channel 16 – Eastlake (talked to two operators) (RO says, "We got a way bigger load than we thought we would have." And "...So we're starting to sag all over the system.") / 13:20:22. Channel 16 – RO to "Berger" / 13:22:07. Channel 16 – "control room"

RO says, "We're sagging all over the system. I need some help." / 13:23:24. Channel 16 – "Control room, Tom" / 13:24:38. Channel 16 – "Unit 9" / 13:26:04. Channel 16 – "Dave" / 13:28:40. Channel 16 "Troy Control". Also general note in RO Dispatch Log.

[6]Example at 13:33:40, Channel 3, FE transcripts.

[7]Investigation Team Site Visit to MISO, Walsh and Seidu interviews.

[8]FE had and ran a state estimator every 30 minutes. This served as a base from which to perform contingency analyses. FE's contingency analysis tool used SCADA and EMS inputs to identify any potential overloads that could result from various line or equipment outages. FE indicated that it has experienced problems with the automatic contingency analysis operation since the system was installed in 1995. As a result, FE operators or engineers ran contingency analysis manually rather than automatically, and were expected to do so when there were questions about the state of the system. Investigation team interviews of FE personnel indicate that the contingency analysis model was likely running but not consulted at any point in the afternoon of August 14.

[9]After the Stuart-Atlanta line tripped, Dayton Power & Light did not immediately provide an update of a change in equipment availability using a standard form that posts the status change in the SDX (System Data Exchange, the NERC database which maintains real-time information on grid equipment status), which relays that notice to reliability coordinators and control areas. After its state estimator failed to solve properly, MISO checked the SDX to make sure that they had properly identified all available equipment and outages, but found no posting there regarding Stuart-Atlanta's outage.

[10]Investigation team field visit, interviews with FE personnel on October 8-9, 2003.

[11] DOE Site Visit to First Energy, September 3, 2003, Interview with David M. Elliott.

[12]FE Report, "Investigation of FirstEnergy's Energy Management System Status on August 14, 2003", Bullet 1, Section 4.2.11.

[13]Investigation team interviews with FE, October 8-9, 2003.

[14]DOE Site Visit at FE, October 8-9, 2003; investigation team was advised that FE had discovered this effect during post-event investigation and testing of the EMS. FE's report "Investigation of FirstEnergy's Energy Management System Status on August 14, 2003" also indicates that this finding was "verified using the strip charts from 8-14-03" (page 23), not that the investigation of this item was instigated by operator reports of such a failure.

[15] There is a conversation between a Phil and a Tom that speaks of "flatlining" 15:01:33. Channel 15. There is no mention of AGC or generation control in the DOE Site Visit interviews with the reliability coordinator.

[16]DOE Site Visit to FE, October 8-9, 2003, Sanicky Interview: "From his experience, it is not unusual for alarms to fail. Often times, they may be slow to update or they may die completely. From his experience as a real-time operator, the fact that the alarms failed did not surprise him." Also from same document, Mike McDonald interview "FE has previously had [servers] down at the same time. The big issue for them was that they were not receiving new alarms."

[17] A "cold" reboot of the XA21 system is one in which all nodes (computers, consoles, etc.) of the system are shut down and then restarted. Alternatively, a given XA21 node can be "warm" rebooted wherein only that node is shut down and restarted, or restarted from a shutdown state. A cold reboot will take significantly longer to perform than a warm one. Also during a cold reboot much more of the system is unavailable for use by the control room operators for visibility or control over the power system. Warm reboots are not uncommon, whereas cold reboots are rare. All reboots undertaken by FE's IT EMSS support personnel on August 14 were warm reboots.

[18]The cold reboot was done in the early morning of 15 August and corrected the alarm problem as hoped.

[19]Example at 14:19, Channel 14, FE transcripts.

[20]Example at 14:25, Channel 8, FE transcripts.

[21]Example at 14:32, Channel 15, FE transcripts.

[22] Investigation team transcript, meeting on September 9, 2003, comments by Mr. Steve Morgan, Vice President Electric Operations:

Mr. Morgan: The sustained outage history for these lines, 2001, 2002, 2003, up until the event, Chamberlin-Harding had zero operations for those two-and-a-half years. And Hanna-Juniper had six operations in 2001, ranging from four minutes to maximum of 34 minutes. Two were unknown, one was lightning, one was a relay failure, and two were really relay scheme mis-operations. They're category other. And typically, that—I don't know what this is particular to operations, that typically occurs when there is a mis-operation. Star-South Canton had no operations in that same period of time, two-and-a-half years. No sustained outages. And Sammis-Star, the line we haven't talked about, also no sustained outages during that two-and-a-half year period.
So is it normal? No. But 345 lines do operate, so it's not unknown.

[23] "Interim Report, Utility Vegetation Management," U.S.-Canada Joint Outage Investigation Task Force, Vegetation Management Program Review, October 2003, page 7.

[24] Investigation team October 2, 2003, fact-finding meeting, Steve Morgan statement.

[25]"FE MISO Findings," page 11.

[26]FE was conducting right-of-way vegetation maintenance on a 5-year cycle, and the tree crew at Hanna-Juniper was three spans away, clearing vegetation near the line, when the contact occurred on August 14. Investigation team 9/9/03 meeting transcript, and investigation field team discussion with the tree-trimming crew foreman.

[27]Based on "FE MISO Findings" document, page 11.

[28] "Interim Report, Utility Vegetation Management," US-Canada Joint Outage Task Force, Vegetation Management Program Review, October 2003, page 6.

[29]Investigation team September 9, 2003 meeting transcripts, Mr. Steve Morgan, First Energy Vice President, Electric System Operations:

Mr. Benjamin: Steve, just to make sure that I'm understanding it correctly, you had indicated that once after Hanna-Juniper relayed out, there wasn't really a problem with voltage on the system until Star-S. Canton operated. But were the system operators aware that when Hanna-Juniper was out, that if Star-S. Canton did trip, they would be outside of operating limits?

Mr. Morgan: I think the answer to that question would have required a contingency analysis to be done probably on demand for that operation. It doesn't appear to me that a contingency analysis, and certainly not a demand contingency analysis, could have been run in that period of time. Other than experience, I don't know that they would have been able

to answer that question. And what I know of the record right now is that it doesn't appear that they ran contingency analysis on demand.
Mr. Benjamin: Could they have done that?
Mr. Morgan: Yeah, presumably they could have.
Mr. Benjamin: You have all the tools to do that?
Mr. Morgan: They have all the tools and all the information is there. And if the State Estimator is successful in solving, and all the data is updated, yeah, they could have. I would say in addition to those tools, they also have access to the planning load flow model that can actually run the same—full load of the model if they want to.

[30] Example synchronized at 14:32 (from 13:32) #18 041 TDC-E2 283.wav, AEP transcripts.

[31] Example synchronized at 14:19 #2 020 TDC-E1 266.wav, AEP transcripts.

[32] Example at 15:36 Channel 8, FE transcripts.

[33] Example at 15:41:30 Channel 3, FE transcripts.

[34] Example synchronized at 15:36 (from 14:43) Channel 20, MISO transcripts.

[35] Example at 15:42:49, Channel 8, FE transcripts.

[36] Example at 15:46:00, Channel 8 FE transcripts.

[37] Example at 15:45:18, Channel 4, FE transcripts.

[38] Example at 15:46:00, Channel 8 FE transcripts.

[39] Example at 15:50:15, Channel 12 FE transcripts.

[40] Example synchronized at 15:48 (from 14:55), channel 22, MISO transcripts.

[41] Example at 15:56:00, Channel 31, FE transcripts.

[42] AEP Transcripts CAE1 8/14/2003 14:35 240.

[43] FE Transcripts 15:45:18 on Channel 4 and 15:56:49 on Channel 31.

[44] The operator logs from FE's Ohio control center indicate that the west desk operator knew of the alarm system failure at 14:14, but that the east desk operator first knew of this development at 15:45. These entries may have been entered after the times noted, however.

[45] The investigation team determined that FE was using a different set of line ratings for Sammis-Star than those being used in the MISO and PJM reliability coordinator calculations or by its neighbor AEP. Specifically, FE was operating Sammis-Star assuming that the 345-kV line was rated for summer normal use at 1,310 MVA, with a summer emergency limit rating of 1,310 MVA. In contrast, MISO, PJM and AEP were using a more conservative rating of 950 MVA normal and 1,076 MVA emergency for this line. The facility owner (in this case FE) is the entity which provides the line rating; when and why the ratings were changed and not communicated to all concerned parties has not been determined.

5. The Cascade Stage of the Blackout

Chapter 4 described how uncorrected problems in northern Ohio developed to a point that a cascading blackout became inevitable. However, the Task Force's investigation also sought to understand how and why the cascade spread and stopped as it did. As detailed below, the investigation determined the sequence of events in the cascade, and in broad terms how it spread and how it stopped in each general geographic area.[1]

Why Does a Blackout Cascade?

Major blackouts are rare, and no two blackout scenarios are the same. The initiating events will vary, including human actions or inactions, system topology, and load/generation balances. Other factors that will vary include the distance between generating stations and major load centers, voltage profiles, and the types and settings of protective relays in use.

Most wide-area blackouts start with short circuits (faults) on several transmission lines in short succession—sometimes resulting from natural causes such as lightning or wind or, as on August 14, resulting from inadequate tree management in right-of-way areas. A fault causes a high current and low voltage on the line containing the fault. A protective relay for that line detects the high current and low voltage and quickly trips the circuit breakers to isolate that line from the rest of the power system.

A cascade occurs when there is a sequential tripping of numerous transmission lines and generators in a widening geographic area. A cascade can be triggered by just a few initiating events, as was seen on August 14. Power swings and voltage fluctuations caused by these initial events can cause other lines to detect high currents and low voltages that appear to be faults, even when faults do not actually exist on those other lines. Generators are tripped off during a cascade to protect them from severe power and voltage swings. Relay protection systems work well to protect lines and generators from damage and to isolate them from the system under normal, steady conditions. However, when power system operating and design criteria are violated as a result of several outages occurring at the same time, most common protective relays cannot distinguish between the currents and voltages seen in a system cascade from those caused by a fault. This leads to more and more lines and generators being tripped, widening the blackout area.

How Did the Cascade Evolve on August 14?

At 16:05:57 Eastern Daylight Time, the trip and lock-out of FE's Sammis-Star 345 kV line set off a cascade of interruptions on the high voltage system, causing electrical fluctuations and facility trips as within seven minutes the blackout rippled from the Akron area across much of the northeast United States and Canada. By 16:13 EDT, more than 263 power plants (531 individual generating units) had been lost, and tens of millions of people in the United States and Canada were without electric power.

Chapter 4 described the four phases that led to the initiation of the cascade at about 16:06 EDT. After 16:06 EDT, the cascade evolved in three distinct phases:

- **Phase 5.** The collapse of FE's transmission system induced unplanned power surges across the region. Shortly before the collapse, large electricity flows were moving across FE's system from generators in the south (Tennessee, Kentucky, Missouri) to load centers in northern Ohio, eastern Michigan, and Ontario. This pathway in northeastern Ohio became unavailable with the collapse of FE's transmission system. The electricity then took alternative paths to the load centers located along the shore of Lake Erie. Power surged in from western Ohio and Indiana on one side and from Pennsylvania through New York and Ontario around the northern side of Lake Erie. Transmission lines in these areas, however, were already heavily loaded with normal flows, and some of them began to trip.

- **Phase 6.** The northeast then separated from the rest of the Eastern Interconnection due to these additional power surges. The power surges resulting from the FE system failures caused lines in neighboring areas to see overloads that caused impedance relays to operate. The result was a wave of line trips through western Ohio that separated AEP from FE. Then the line trips progressed northward into Michigan separating western and eastern Michigan.

  With paths cut from the west, a massive power surge flowed from PJM into New York and Ontario in a counter-clockwise flow around Lake Erie to serve the load still connected in eastern Michigan and northern Ohio. The relays on the lines between PJM and New York saw this massive power surge as faults and tripped those lines. Lines in western Ontario also became overloaded and tripped. The entire northeastern United States and the province of Ontario then became a large electrical island separated from the rest of the Eastern Interconnection. This large island, which had been importing power prior to the cascade, quickly became unstable as there was not sufficient generation in operation within it to meet electricity demand. Systems to the south and west of the split, such as PJM, AEP and others further away remained intact and were mostly unaffected by the outage. Once the northeast split from the rest of the Eastern Interconnection, the cascade was isolated.

Phase 7. In the final phase, the large electrical island in the northeast was deficient in generation and unstable with large power surges and swings in frequency and voltage. As a result, many lines and generators across the disturbance area tripped, breaking the area into several electrical islands. Generation and load within these smaller islands was often unbalanced, leading to further tripping of lines and generating units until equilibrium was established in each island. Although much of the disturbance area was fully blacked out in this process, some islands were able to reach equilibrium without total loss of service. For example, most of New England was stabilized and generation and load restored to balance. Approximately half of the generation and load remained on in western New York, which has an abundance of generation. By comparison, other areas with large load centers and insufficient generation nearby to meet that load collapsed into a blackout condition (Figure 5.1).

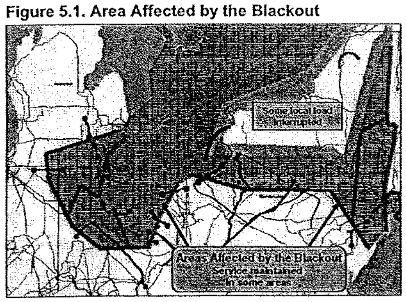
Impedance Relays

The most common protective device for transmission lines is the impedance relay (also known as a distance relay). It detects changes in currents and voltages to determine the apparent impedance of the line. A relay is installed at each end of a transmission line. Each relay is actually three relays within one, with each element looking at a particular "zone" or length of the line being protected.

- The first zone looks for faults on the line itself, with no intentional delay.
- The second zone is set to look at the entire line and slightly beyond the end of the line with a slight time delay. The slight delay on the zone 2 relay is useful when a fault occurs near one end of the line. The zone 1 relay near that end operates quickly to trip the circuit breakers on that end. However, the zone 1 relay on the far end may not be able to tell if the fault is just inside the line or just beyond the line. In this case, the zone 2 relay on the far end trips the breakers after a short delay, allowing the zone 1 relay near the fault to open the line on that end first.
- The third zone is slower acting and looks for faults well beyond the length of the line. It can be thought of as a backup, but would generally not be used under normal conditions.

An impedance relay operates when the apparent impedance, as measured by the current and voltage seen by the relay, falls within any one of the operating zones for the appropriate amount of time for that zone. The relay will trip and cause circuit breakers to operate and isolate the line. Typically, Zone 1 and 2 operations are used to protect lines from faults. Zone 3 relay operations, as in the August 14 cascade, can occur if there are apparent faults caused by large swings in voltages and currents.

Figure 5.1. Area Affected by the Blackout



What Stopped the August 14 Blackout from Cascading Further?

The investigation concluded that one or more of the following likely determined where and when the cascade stopped spreading:

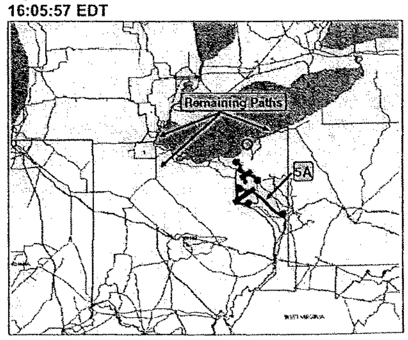
- The effects of a disturbance travel over power lines and become dampened the further they are from the initial point, much like the ripple from a stone thrown in a pond. Thus, the voltage and current swings seen by relays on lines farther away from the initial disturbance are not as severe, and at some point they are no longer sufficient to induce lines to trip.
- Higher voltage lines and more densely networked lines, such as the 500-kV system in PJM and the 765-kV system in AEP, are better able to absorb voltage and current swings and thus serve as a barrier to the spreading of a cascade. As seen in Phase 6, the cascade progressed into western Ohio and then northward through Michigan through the areas that had the fewest transmission lines. Because there were fewer lines, each line absorbed more of the power and voltage surges and was more vulnerable to tripping. A similar effect was seen toward the east as the lines between New York and Pennsylvania, and eventually northern New Jersey tripped. The cascade of transmission line outages became isolated after the northeast United States and Ontario were completely separated from the rest of the Eastern Interconnection and no more power flows were possible into the northeast (except the DC ties from Quebec, which continued to supply power to western New York and New England).
- Some areas, due to line trips, were isolated from the portion of the grid that was experiencing instability. Many of these areas retained sufficient on-line generation or the capacity to import power from other parts of the grid, unaffected by the surges or instability, to meet demand. As the cascade progressed, and more generators and lines tripped off to protect themselves from severe damage, and some areas completely separated from the unstable part of the Eastern Interconnection. In many of these areas there was sufficient generation to stabilize the system. After the large island was formed in the northeast, symptoms of frequency and voltage collapse became evident. In some parts of the large area, the system was too unstable and shut itself down. In other parts, there was sufficient generation, coupled with fast-acting automatic load shedding, to stabilize frequency and voltage. In this manned, most of New England remained energized. Approximately half of the generation and load remained on in western New York, aided by generation in southern Ontario that split and stayed with western New York. There were other smaller isolated pockets of load and generation that were able to achieve equilibrium and remain energized.

Phase 5: 345-kV Transmission System Cascade in Northern Ohio and South-Central Michigan

Overview of This Phase

This initial phase of the cascade began because after the loss of FE's Sammis-Star 345-kV line and the underlying 138-kV system, there were no large transmission paths left from the south to support the significant amount of load in northern Ohio (Figure 5.2). This placed a significant load burden

Figure 5.2. Sammis-Star 345-kV Line Trip, 16:05:57 EDT



onto the transmission paths north and northwest into Michigan, causing a steady loss of lines and power plants.

Key Events in This Phase

5A) 16:05:57 EDT: Sammis-Star 345-kV tripped.

5B) 16:08:59 EDT: Galion-Ohio Central-Muskingum 345-kV line tripped.

5C) 16:09:06 EDT: East Lima-Fostoria Central 345-kV line tripped, causing major power swings through New York and Ontario into Michigan.

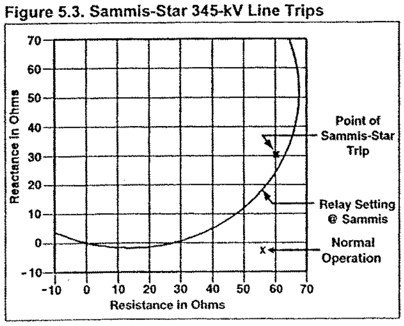
5D) 16:09:08 EDT to 16:10:27 EDT: Several power plants lost, totaling 937 MW.

5A) Sammis-Star 345-kV Tripped: 16:05:57 EDT

Sammis-Star did not trip due to a short circuit to ground (as did the prior 345-kV lines that tripped). Sammis-Star tripped due to protective relay action that measured low apparent impedance (depressed voltage divided by abnormally high line current) (Figure 5.3). There was no fault and no major power swing at the time of the trip—rather, high flows above the line's emergency rating together with depressed voltages caused the overload to appear to the protective relays as a remote fault on the system. In effect, the relay could no longer differentiate between a remote three-phase fault and an exceptionally high line-load condition. Moreover, the reactive flows (VArs) on the line were almost ten times higher than they had been earlier in the day. The relay operated as it was designed to do.

The Sammis-Star 345-kV line trip completely severed the 345-kV path into northern Ohio from southeast Ohio, triggering a new, fast-paced sequence of 345-kV transmission line trips in which each line trip placed a greater flow burden on those lines remaining in service. These line outages left only three paths for power to flow into northern Ohio: (1) from northwest Pennsylvania to northern Ohio around the south shore of Lake Erie, (2) from southern Ohio, and (3) from eastern Michigan and Ontario. The line interruptions substantially weakened northeast Ohio as a source of power to eastern Michigan, making the Detroit area more reliant on 345-kV lines west and northwest of Detroit, and from northwestern Ohio to eastern Michigan.

Figure 5.3. Sammis-Star 345-kV Line Trips



Transmission Lines into Northwestern Ohio Tripped, and Generation Tripped in South Central Michigan and Northern Ohio: 16:08:59 EDT to 16:10:27 EDT

5B) Galion-Ohio Central-Muskingum 345-kV line tripped: 16:08:59 EDT

5C) East Lima-Fostoria Central 345-kV line tripped, causing a large power swing from Pennsylvania and New York through Ontario to Michigan: 16:09:05 EDT

The tripping of the Galion-Ohio Central-Muskingum and East Lima-Fostoria Central 345-kV transmission lines removed the transmission paths from southern and western Ohio into northern Ohio and eastern Michigan. Northern Ohio was connected to eastern Michigan by only three 345-kV transmission lines near the southwestern

System Oscillations

The electric power system constantly experiences small, stable power oscillations. They occur as generator rotors accelerate or slow down while rebalancing electrical output power to mechanical input power, to respond to changes in load or network conditions. These oscillations are observable in the power flow on transmission lines that link generation to load or in the tie lines that link different regions of the system together. The greater the disturbance to the network, the more severe these oscillations can become, even to the point where flows become so great that protective relays trip the connecting lines, just as a rubber band breaks when stretched too far. If the lines connecting different electrical regions separate, each region will drift to its own frequency.

Oscillations that grow in amplitude are called unstable oscillations. Oscillations are also sometimes called power swings, and once initiated they flow back and forth across the system rather like water sloshing in a rocking tub.

bend of Lake Erie. Thus, the combined northern Ohio and eastern Michigan load centers were left connected to the rest of the grid only by: (1) transmission lines eastward from northeast Ohio to northwest Pennsylvania along the southern shore of Lake Erie, and (2) westward by lines west and northwest of Detroit, Michigan and from Michigan into Ontario (Figure 5.4).

The East Lima-Fostoria Central 345-kV line tripped at 16:09:06 EDT due to high currents and low voltage, and the resulting large power swings (measuring about 400 MW when they passed through NYPA's Niagara recorders) marked the moment when the system became unstable. This was the first of several inter-area power and frequency events that occurred over the next two minutes. It was the system's response to the loss of the Ohio-Michigan transmission paths (above), and the stress that the still-high Cleveland, Toledo and Detroit loads put onto the surviving lines and local generators.

In Figure 5.5, a high-speed recording of 345-kV flows past Niagara Falls shows the New York to Ontario power swing, which continued to oscillate for over 10 seconds. The recording shows the magnitude of subsequent flows triggered by the trips of the Hampton-Pontiac and Thetford-Jewell 345-kV lines in Michigan and the Perry-Ashtabula 345-kV line linking the Cleveland area to Pennsylvania. The very low voltages on the northern Ohio transmission system made it very difficult for the generation in the Cleveland and Lake Erie area to maintain synchronization with the Eastern Interconnection. Over the next two minutes, generators in this area shut down after reaching a point of no recovery as the stress level across the remaining ties became excessive.

Before this first major power swing on the Michigan/Ontario interface, power flows in the NPCC Region (Ontario and the Maritimes, New England, New York, and the mid-Atlantic portion of PJM) were typical for the summer period, and well within acceptable limits. Transmission and generation facilities were then in a secure state across the NPCC.

5D) Multiple Power Plants Tripped, Totaling 937 MW: 16:09:08 to 16:10:27 EDT

- Michigan Cogeneration Venture plant reduction of 300 MW (from 1,263 MW to 963 MW)
- Kinder Morgan units 1 and 2 trip (200 MW total)
- Avon Lake 7 unit trips (82 MW)
- Berger 3, 4, and 5 units trip (355 MW total)

The Midland Cogeneration Venture (MCV) plant is in central Michigan. Kinder Morgan is in south-central Michigan. The large power reversal caused frequency and voltage fluctuations at the plants. Their automatic control systems responded to these transients by trying to adjust output to raise voltage or respond to the frequency changes, but subsequently tripped off-line. The Avon Lake and Burger units, in or near Cleveland, likely tripped off due to the low voltages prevailing in the Cleveland area and 138-kV line trips near Burger 138-kV substation (northern Ohio) (Figure 5.6).

Power flows into Michigan from Indiana increased to serve loads in eastern Michigan and northern Ohio (still connected to the grid through northwest Ohio and Michigan) and voltages

Figure 5.4. Ohio 345-kV Lines Trip, 16:08:59 to 16:09:07 EDT

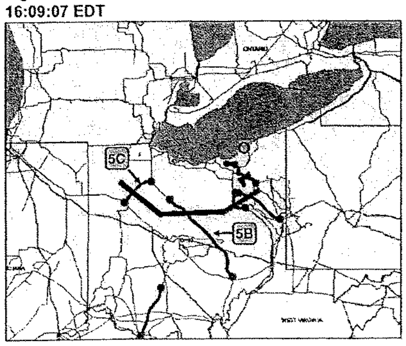
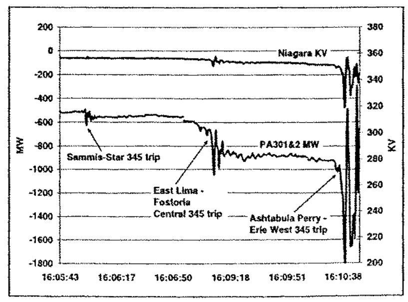


Figure 5.5. New York-Ontario Line Flows at Niagara



Note: Does not include 230-kV line flow.

dropped from the imbalance between high loads and limited transmission and generation capability.

Phase 6: The Full Cascade

Between 16:10:36 EDT and 16:13 EDT, thousands of events occurred on the grid, driven by physics and automatic equipment operations. When it was over, much of the northeast United States and the Canadian province of Ontario was in the dark.

Key Phase 6 Events

Transmission Lines Disconnected Across Michigan and Northern Ohio, Generation Shut Down in Central Michigan and Northern Ohio, and Northern Ohio Separated from Pennsylvania: 16:10:36 EDT to 16:10:39 EDT

6A) Transmission and more generation tripped within Michigan: 16:10:36 EDT to 16:10:37 EDT:

Argenta-Battlecreek 345-kV line tripped

Battlecreek-Oneida 345-kV line tripped

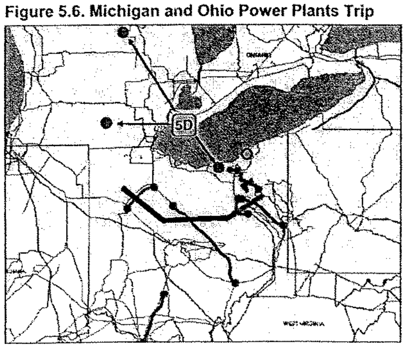
Argenta-Tompkins 345-kV line tripped

Sumpter Units 1, 2, 3, and 4 units tripped (300 MW near Detroit)

MCV Plant output dropped from 944 MW to 109 MW.

Together, the above line outages interrupted the east-to-west transmission paths into the Detroit area from south-central Michigan. The Sumpter generation units tripped in response to under-voltage on the system. Michigan lines northwest of Detroit then began to trip, as noted below (Figure 5.7).

Figure 5.6. Michigan and Ohio Power Plants Trip



6B) More Michigan lines tripped: 16:10:37 EDT to 16:10:38 EDT

Hampton-Pontiac 345-kV line tripped

Thetford-Jewell 345-kV line tripped

These 345-kV lines connect Detroit to the north. When they tripped out of service, it left the loads in Detroit, Toledo, Cleveland, and their surrounding areas served only by local generation and the lines connecting Detroit east to Ontario and Cleveland east to northeast Pennsylvania.

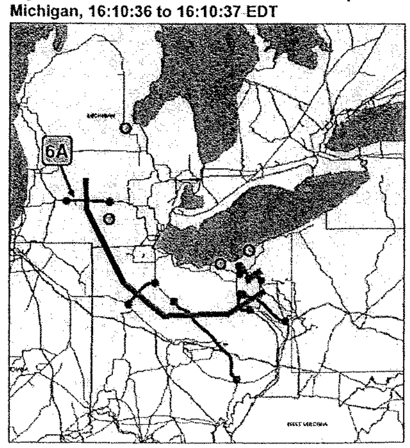
6C) Cleveland separated from Pennsylvania, flows reversed and a huge power surge flowed counter-clockwise around Lake Erie: 16:10:38.6 EDT

Perry-Ashtabula-Erie West 345-kV line tripped: 16:10:38.6 EDT

Large power surge to serve loads in eastern Michigan and northern Ohio swept across Pennsylvania, New Jersey, and New York through Ontario into Michigan: 16:10:38.6 EDT.

Perry-Ashtabula-West Erie was the last 345-kV line connecting northern Ohio to the east. This line's trip separated the Ohio 345-kV transmission system from Pennsylvania. When it tripped, the load centers in eastern Michigan and northern Ohio remained connected to the rest of the Eastern Interconnection only at the interface between the

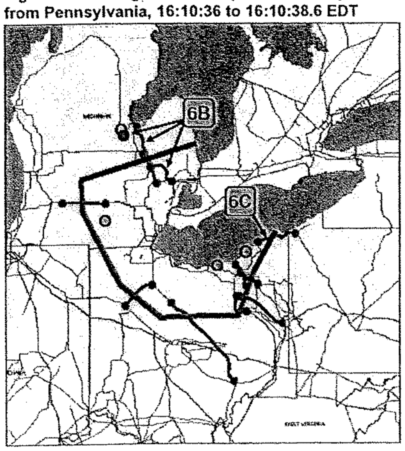
Figure 5.7. Transmission and Generation Trips in Michigan, 16:10:36 to 16:10:37 EDT



Michigan and Ontario systems (Figure 5.8). Eastern Michigan and northern Ohio now had little internal generation left and voltage was declining. Between 16:10:39 EDT and 16:10:50 EDT under-frequency load shedding in the Cleveland area operated and interrupted about 1,750 MW of load. The frequency in the Cleveland area (by then separated from the Eastern Interconnection to the south) was also dropping rapidly and the load shedding was not enough to arrest the frequency decline. Since the electrical system always seeks to balance load and generation, the high loads in Cleveland drew power over the only major transmission path remaining—the lines from eastern Michigan east into Ontario.

Before the loss of the Perry-Ashtabula-West Erie line, 437 MW was flowing from Michigan into Ontario. At 16:10:38.6 EDT, after the other transmission paths into Michigan and Ohio failed, the power that had been flowing over them reversed direction in a fraction of a second. Electricity began flowing toward Michigan via a giant loop through Pennsylvania and into New York and Ontario and then into Michigan via the remaining transmission path. Flows at Niagara Falls 345-kV lines measured over 800 MW, and over 3,500 MW at the Ontario to Michigan interface (Figure 5.9). This sudden large change in power flows drastically lowered voltage and increased current levels on the transmission lines along the Pennsylvania-New York transmission interface.

Figure 5.8. Michigan Lines Trip and Ohio Separates from Pennsylvania, 16:10:36 to 16:10:38.6 EDT

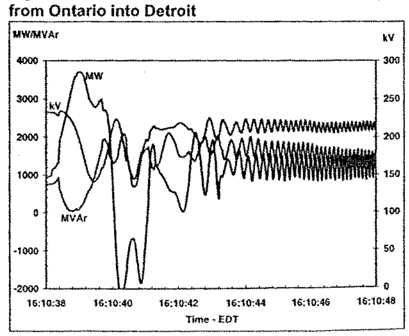


This was a transient frequency swing, so frequency was not the same across the Eastern Interconnection. As Figure 5.8 shows, this frequency imbalance and the accompanying power swing resulted in a rapid rate of voltage decay. Flows into Detroit exceeded 3,500 MW and 1,500 MVAr, meaning that the power surge was draining both active and reactive power out of the northeast to prop up the low voltages in eastern Michigan and Detroit. This magnitude of reactive power draw caused voltages in Ontario and New York to drop. At the same time, local voltages in the Detroit area were low because there was still not enough supply to meet load. Detroit would soon black out (as evidenced by the rapid power swings decaying after 16:10:43 EDT).

Between 16:10:38 and 16:10:41 EDT, the power surge caused a sudden extraordinary increase in system frequency to 60.3 Hz. A series of circuits tripped along the border between PJM and the NYISO due to apparent impedance faults (short circuits). The surge also moved into New England and the Maritimes region of Canada. The combination of the power surge and frequency rise caused 380 MW of pre-selected Maritimes generation to drop off-line due to the operation of the New Brunswick Power "Loss of Line 3001" Special Protection System. Although this system was designed to respond to failure of the 345-kV link between the Maritimes and New England, it operated in response to the effects of the power surge. The link remained intact during the event.

In summary, the Perry-Ashtabula-Erie West 345-kV line trip at 16:10:38.6 EDT was the point when the Northeast entered a period of transient instability and a loss of generator synchronism.

Figure 5.9. Active and Reactive Power and Voltage from Ontario into Detroit



Western Pennsylvania Separated from New York: 16:10:39 EDT to 16:10:44 EDT

6D) 16:10:39 EDT, Homer City-Watercure Road 345-kV

Homer City-Stolle Road 345-kV: 16:10:39 EDT

6E) South Ripley-Erie East 230-kV, and South Ripley-Dunkirk 230-kV: 16:10:44 EDT

East Towanda-Hillside 230-kV: 16:10:44 EDT

Responding to the surge of power flowing north out of Pennsylvania through New York and Ontario into Michigan, relays on these lines activated on apparent impedance within a five-second period and separated Pennsylvania from New York (Figure 5.10).

At this point, the northern part of the Eastern Interconnection (including eastern Michigan and northern Ohio) remained connected to the rest of the Interconnection at only two locations: (1) in the east through the 500-kV and 230-kV ties between New York and northeast New Jersey, and (2) in the west through the long and therefore fragile 230-kV transmission path connecting Ontario to Manitoba and Minnesota.

Figure 5.10. Western Pennsylvania Separates from New York, 16:10:39 EDT to 16:10:44 EDT

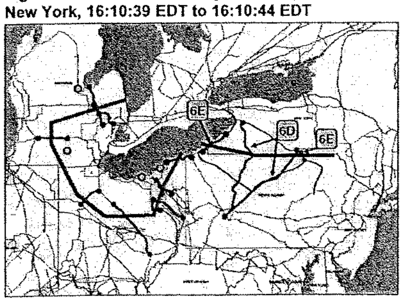
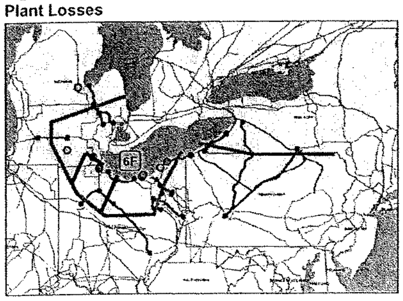


Figure 5.11. More Transmission Line and Power Plant Losses



Because the demand for power in Michigan, Ohio, and Ontario was drawing on lines through New York and Pennsylvania, heavy power flows were moving northward from New Jersey over the New York tie lines to meet those power demands, exacerbating the power swing.

6F) Conditions in Northern Ohio and Eastern Michigan Degraded Further, With More Transmission Lines and Power Plants Failing: 16:10:39 to 16:10:46 EDT

Bayshore-Monroe 345-kV line

Allen Junction-Majestic-Monroe 345-kV line

Majestic 345-kV Substation: one terminal opened on all 345-kV lines

Perry-Ashtabula-Erie West 345-kV line terminal at Ashtabula 345/138-kV substation

Fostoria Central-Galion 345-kV line

Beaver-Davis Besse 345-kV line

Galion-Ohio Central-Muskingum 345 tripped at Galion

Six power plants, for a total of 3,097 MW of generation, tripped off-line:

Lakeshore unit 18 (156 MW, near Cleveland)

Bay Shore Units 1-4 (551 MW near Toledo)

Eastlake 1, 2, and 3 units (403 MW total, near Cleveland)

Avon Lake unit 9 (580 MW, near Cleveland)

Perry 1 nuclear unit (1,223 MW, near Cleveland)

Ashtabula unit 5 (184 MW, near Cleveland)

Back in northern Ohio, the trips of the Majestic 345-kV substation in southeast Michigan, the Bay Shore-Monroe 345-kV line, and the Ashtabula 345/138-kV transformer created a Toledo and Cleveland electrical "island" (Figure 5.11). Frequency in this large island began to fall rapidly. This led to a series of power plants in the area shutting down due to the operation of underfrequency relays, including the Bay Shore units. When the Beaver-Davis Besse 345-kV line connecting Cleveland and Toledo tripped, it left the Cleveland area completely isolated. Cleveland area load was disconnected by automatic underfrequency load-shedding (approximately 1,300

MW in the greater Cleveland area), and another 434 MW of load was interrupted after the generation remaining within this transmission "island" was tripped by under-frequency relays. Portions of Toledo blacked out from automatic under-frequency load-shedding but most of the Toledo load was restored by automatic reclosing of lines such as the East Lima-Fostoria Central 345-kV line and several lines at the Majestic 345-kV substation.

The prolonged period of system-wide low voltage around Detroit caused the remaining generators in that area, then running at maximum mechanical output, to begin to pull out of synchronous operation with the rest of the grid. Those plants raced ahead of system frequency with higher than normal revolutions per second by each generator. But when voltage returned to near-normal, the generator could not fully pull back its rate of revolutions, and ended up producing excessive temporary output levels, still out of step with the system. This is evident in Figure 5.9 (above), which shows at least two sets of generator "pole slips" by plants in the Detroit area between 16:10:40 EDT and 16:10:42 EDT. Several large units around Detroit—Belle River, St. Clair, Greenwood, Monroe and Fermi—all recorded tripping for out-of-step operation due to this cause. The Perry 1 nuclear unit, located on the southern shore of Lake Erie near the border with Pennsylvania, and a number of other units near Cleveland tripped off-line by unit under-frequency protection.

6G) Transmission paths disconnected in New Jersey and northern Ontario, isolating the northeast portion of the Eastern Interconnection: 16:10:42 EDT to 16:10:45 EDT

- Four power plants producing 1,630 MW tripped off-line
  - Greenwood unit 11 and 12 tripped (225 MW near Detroit)
  - Belle River unit 1 tripped (600 MW near Detroit)
  - St. Clair unit 7 tripped (221 MW, DTE unit)
  - Trenton Channel units 7A, 8 and 9 tripped (584 MW, DTE units)
- Keith-Waterman 230-kV tripped, 16:10:43 EDT
- Wawa-Marathon W21-22 230-kV line tripped, 16:10:45 EDT
- Branchburg-Ramapo 500-kV line tripped, 16:10:45 EDT

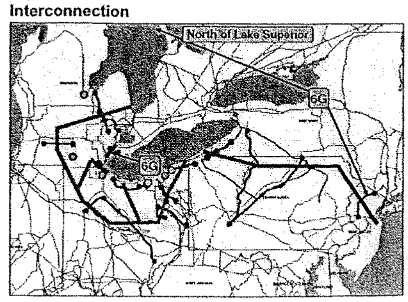
A significant amount of the remaining generation serving Detroit tripped off-line in response to these events. At 16:10:43 EDT, eastern Michigan was still connected to Ontario, but the Keith-Waterman 230-kV line that forms part of that interface disconnected due to apparent impedance (Figure 5.12).

At 16:10:45 EDT, northwest Ontario separated from the rest of Ontario when the Wawa-Marathon 230-kV lines disconnected along the northern shore of Lake Superior. This separation left the loads in the far northwest portion of Ontario connected to the Manitoba and Minnesota systems, and protected them from the blackout.

The Branchburg-Ramapo 500-kV line between New Jersey and New York was the last major transmission path remaining between the Eastern Interconnection and the area ultimately affected by the blackout. That line disconnected at 16:10:45 EDT along with the underlying 230 and 138-kV lines in northeast New Jersey. This left the northeast portion of New Jersey connected to New York, while Pennsylvania and the rest of New Jersey remained connected to the rest of the Eastern Interconnection.

At this point, the Eastern Interconnection was split into two major sections. To the north and east of the separation point lay New York City, northern New Jersey, New York state, New England, the Canadian Maritime provinces, eastern Michigan, the majority of Ontario, and the Québec system. The rest of the Eastern Interconnection, to the south and west of the separation boundary, was not seriously affected by the blackout.

Figure 5.12. Northeast Disconnects from Eastern Interconnection



Phase 7: Several Electrical Islands Formed in Northeast U.S. and Canada: 16:10:46 EDT to 16:12 EDT

Overview of This Phase

New England (except southwestern Connecticut) and the Maritimes separated from New York and remained intact; New York split east to west: 16:10:46 EDT to 16:11:57 EDT. Figure 5.13 illustrates the events of this phase.

During the next 3 seconds, the islanded northern section of the Eastern Interconnection broke apart internally.

7A) New York-New England transmission lines disconnected: 16:10:46 EDT to 16:10:47 EDT

7B) 16:10:49 EDT, New York transmission system split east to west

7C) The Ontario system just west of Niagara Falls and west of St. Lawrence separated from the western New York island: 16:10:50 EDT

7D) Southwest Connecticut separated from New York City: 16:11:22 EDT

7E) Remaining transmission lines between Ontario and eastern Michigan separated: 16:11:57 EDT

Key Phase 7 Events

7A) New York-New England Transmission Lines Disconnected: 16:10:46 EDT to 16:10:49 EDT

Over the period 16:10:46 EDT to 16:10:49 EDT, the New York to New England tie lines tripped. The power swings continuing through the region caused this separation, and caused Vermont to lose approximately 70 MW of load.

The ties between New York and New England disconnected, and most of the New England area along with Canada's Maritime Provinces became an island with generation and demand balanced close enough that it was able to remain operational. New England had been exporting close to 600 MW to New York, and its system experienced continuing fluctuations until it reached electrical equilibrium. Before the Maritimes-New England separated from the Eastern Interconnection at approximately 16:11 EDT, voltages became depressed due to the large power swings across portions of New England. Some large customers disconnected themselves automatically.[2] However, southwestern Connecticut separated from New England and remained tied to the New York system for about 1 minute.

Due to its geography and electrical characteristics, the Quebec system in Canada is tied to the remainder of the Eastern Interconnection via high voltage DC links instead of AC transmission lines. Quebec was able to survive the power surges with only small impacts because the DC connections shielded it from the frequency swings.

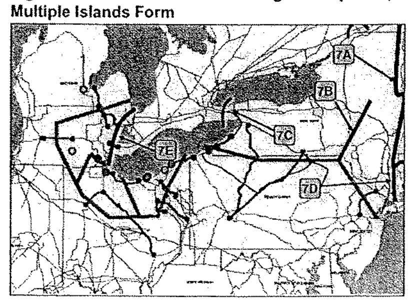
7B) New York Transmission Split East-West: 16:10:49 EDT

The transmission system split internally within New York, with the eastern portion islanding to contain New York City, northern New Jersey and southwestern Connecticut. The western portion of New York remained connected to Ontario and eastern Michigan.

7C) The Ontario System Just West of Niagara Falls and West of St. Lawrence Separated from the Western New York Island: 16:10:50 EDT

At 16:10:50 EDT, Ontario and New York separated west of the Ontario/New York interconnection, due to relay operations which disconnected nine 230-kV lines within Ontario. These left most of Ontario isolated to the north. Ontario's large Beck and Saunders hydro stations, along with some Ontario load, the New York Power Authority's (NYPA) Niagara and St. Lawrence hydro stations, and NYPA's 765-kV AC interconnection with Québec, remained connected to the western New York system, supporting the demand in upstate New York.

Figure 5.13. New York and New England Separate, Multiple Islands Form



From 16:10:49 EDT to 16:10:50 EDT, frequency declined below 59.3 Hz, initiating automatic under-frequency load-shedding in Ontario (2,500 MW), eastern New York and southwestern Connecticut. This load-shedding dropped off about 20% of the load across the eastern New York island and about 10% of Ontario's remaining load. Between 16:10:50 EDT and 16:10:56 EDT, the isolation of the southern Ontario hydro units onto the western New York island, coupled with under-frequency load-shedding in the western New York island, caused the frequency in this island to rise to 63.0 Hz due to excess generation.

Three of the tripped 230-kV transmission circuits near Niagara automatically reconnected Ontario to New York at 16:10:56 EDT by reclosing. Even with these lines reconnected, the main Ontario island (still attached to New York and eastern Michigan) was then extremely deficient in generation, so its frequency declined towards 58.8 Hz, the threshold for the second stage of under-frequency load-shedding. Within the next two seconds another 18% of Ontario demand (4,500 MW) automatically disconnected by under-frequency load-shedding. At 16:11:10 EDT, these same three lines tripped a second time west of Niagara, and New York and most of Ontario separated for a final time. Following this separation, the frequency in Ontario declined to 56 Hz by 16:11:57 EDT. With Ontario still supplying 2,500 MW to the Michigan-Ohio load pocket, the remaining ties with Michigan tripped at 16:11:57 EDT. Ontario system frequency declined, leading to a widespread shutdown at 16:11:58 EDT and loss of 22,500 MW of load in Ontario, including the cities of Toronto, Hamilton and Ottawa.

7D) Southwest Connecticut Separated from New York City: 16:11:22 EDT

In southwest Connecticut, when the Long Mountain-Plum Tree line (connected to the Pleasant Valley substation in New York) disconnected at 16:11:22 EDT, it left about 500 MW of southwest Connecticut demand supplied only through a 138-kV underwater tie to Long Island. About two seconds later, the two 345-kV circuits connecting southeastern New York to Long Island tripped, isolating Long Island and southwest Connecticut, which remained tied together by the underwater Norwalk Harbor to Northport 138-kV cable. The cable tripped about 20 seconds later, causing southwest Connecticut to black out.

Within the western New York island, the 345-kV system remained intact from Niagara east to the Utica area, and from the St. Lawrence/Plattsburgh area south to the Utica area through both the 765-kV and 230-kV circuits. Ontario's Beck and Saunders generation remained connected to New York at Niagara and St. Lawrence, respectively, and this island stabilized with about 50% of the pre-event load remaining. The boundary of this island moved southeastward as a result of the reclosure of Fraser to Coopers Corners 345-kV at 16:11:23 EDT.

As a result of the severe frequency and voltage changes, many large generating units in New York and Ontario tripped off-line. The eastern island of

Under-frequency Load-Shedding

Since in an electrical system load and generation must balance, if a system loses a great deal of generation suddenly it will if necessary drop load to balance that loss. Unless that load drop is managed carefully, such an imbalance can lead to a voltage collapse and widespread outages. In an electrical island with declining frequency, if sufficient load is quickly shed, frequency will begin to rise back toward 60 Hz.

After the blackouts of the 1960s, some utilities installed under-frequency load-shedding mechanisms on their distribution systems. These systems are designed to drop pre-designated customer load automatically if frequency gets too low (since low frequency indicates too little generation relative to load), starting generally when frequency reaches 59.2 Hz. Progressively more load is set to drop as frequency levels fall farther. The last step of customer load shedding is set at the frequency level just above the set point for generation under-frequency protection relays (57.5 Hz), to prevent frequency from falling so low that the generators could be damaged (see Figure 2.4).

Not every utility or control area handles load-shedding in the same way. In NPCC, following the Northeast blackout of 1965, the region adopted automatic load-shedding criteria to prevent a recurrence of the cascade and better protect system equipment from damage due to a high-speed system collapse.

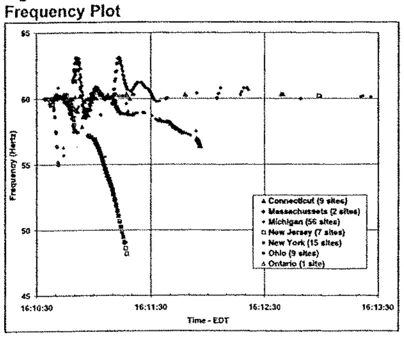
New York, including the heavily populated areas of southeastern New York, New York City, and Long Island, experienced severe frequency and voltage decline. At 16:11:29 EDT, the New Scotland to Leeds 345-kV circuits tripped, separating the island into northern and southern sections. The small remaining load in the northern portion of the eastern island (the Albany area) retained electric service, supplied by local generation until it could be resynchronized with the western New York island.

7E) Remaining Transmission Lines Between Ontario and Eastern Michigan Separated: 16:11:57 EDT

Before the blackout, New England, New York, Ontario, eastern Michigan, and northern Ohio were scheduled net importers of power. When the western and southern lines serving Cleveland, Toledo, and Detroit collapsed, most of the load remained on those systems, but some generation had tripped. This exacerbated the generation/load imbalance in areas that were already importing power. The power to serve this load came through the only major path available, through Ontario (IMO). After most of IMO was separated from New York and generation to the north and east, much of the Ontario load and generation was lost; it took only moments for the transmission paths west from Ontario to Michigan to fail.

When the cascade was over at about 16:12 EDT, much of the disturbed area was completely blacked out, but there were isolated pockets that still had service because load and generation had reached equilibrium. Ontario's large Beck and Saunders hydro stations, along with some Ontario load, the New York Power Authority's (NYPA)

Figure 5.14. Electric Islands Reflected in Frequency Plot



Niagara and St. Lawrence hydro stations, and NYPA's 765-kV AC interconnection with Québec, remained connected to the western New York system, supporting demand in upstate New York.

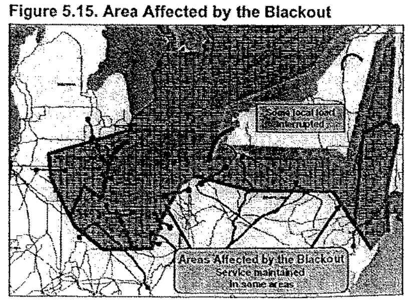
Electrical islanding. Once the northeast became isolated, it grew generation-deficient as more and more power plants tripped off-line to protect themselves from the growing disturbance. The severe swings in frequency and voltage in the area caused numerous lines to trip, so the isolated area broke further into smaller islands. The load/generation mismatch also affected voltages and frequency within these smaller areas, causing further generator trips and automatic under-frequency load-shedding, leading to blackout in most of these areas.

Figure 5.14 shows frequency data collected by the distribution-level monitors of Softswitching Technologies, Inc. (a commercial power quality company serving industrial customers) for the area affected by the blackout. The data reveal at least five separate electrical islands in the Northeast as the cascade progressed. The two paths of red diamonds on the frequency scale reflect the Albany area island (upper path) versus the New York city island, which declined and blacked out much earlier.

Cascading Sequence Essentially Complete: 16:13 EDT

Most of the Northeast (the area shown in gray in Figure 5.15) was now blacked out. Some isolated areas of generation and load remained on-line for several minutes. Some of those areas in which a close generation-demand balance could be maintained remained operational; other generators ultimately tripped off line and the areas they served were blacked out.

Figure 5.15. Area Affected by the Blackout



One relatively large island remained in operation serving about 5,700 MW of demand, mostly in western New York. Ontario's large Beck and Saunders hydro stations, along with some Ontario load, the New York Power Authority's (NYPA) Niagara and St. Lawrence hydro stations, and NYPA's 765-kV AC interconnection with Québec, remained connected to the western New York system, supporting demand in upstate New York. This island formed the basis for restoration in both New York and Ontario.

The entire cascade sequence is depicted graphically in Figure 5.16 on the following page.

Why the Blackout Stopped Where It Did

Extreme system conditions can damage equipment in several ways, from melting aluminum conductors (excessive currents) to breaking turbine blades on a generator (frequency excursions). The power system is designed to ensure that if conditions on the grid (excessive or inadequate voltage, apparent impedance or frequency) threaten the safe operation of the transmission lines, transformers, or power plants, the threatened equipment automatically separates from the network to protect itself from physical damage. Relays are the devices that effect this protection.

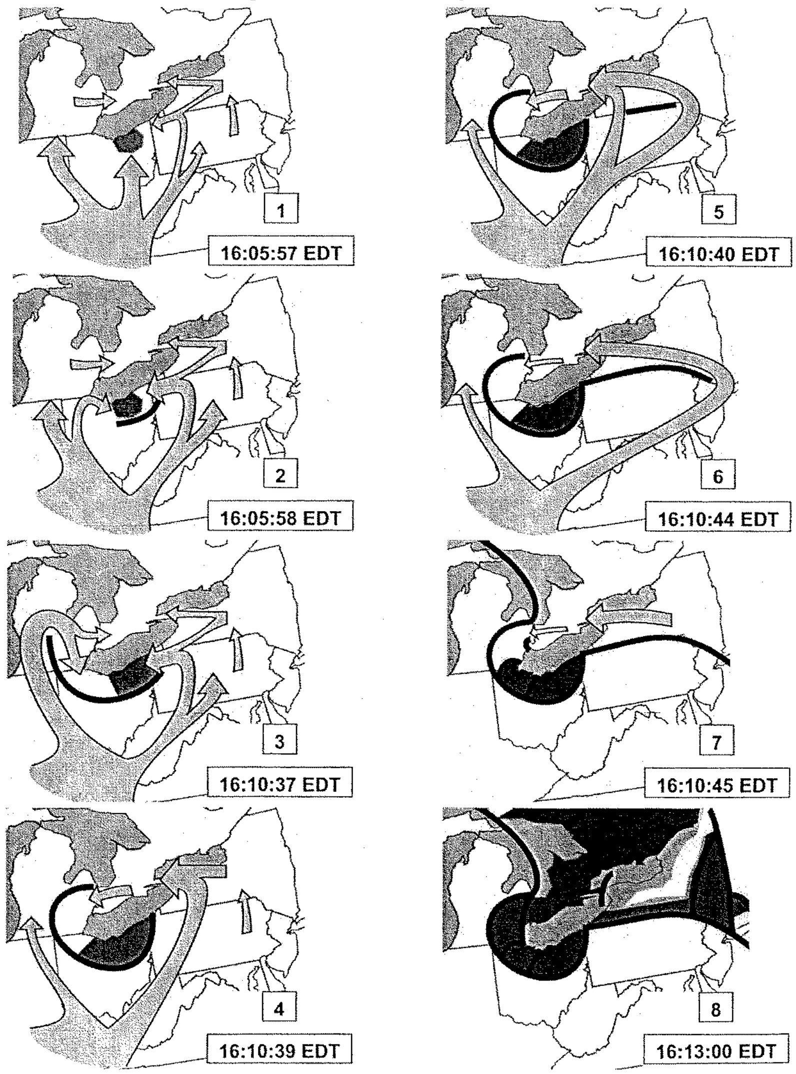
Generators are usually the most expensive units on an electrical system, so system protection schemes are designed to drop a power plant off the system as a self-protective measure if grid conditions become unacceptable. When unstable power swings develop between a group of generators that are losing synchronization (matching frequency) with the rest of the system, the only way to stop the oscillations is to stop the flows entirely by separating all interconnections or ties between the unstable generators and the remainder of the system. The most common way to protect generators from power oscillations is for the transmission system to detect the power swings and trip at the locations detecting the swings—ideally before the swing reaches and harms the generator.

On August 14, the cascade became a race between the power surges and the relays. The lines that tripped first were generally the longer lines, because the relay settings required to protect these lines use a longer apparent impedance tripping zone, which a power swing enters sooner, in comparison to the shorter apparent impedance zone targets set on shorter, networked lines. On August 14, relays on long lines such as the Homer City-Watercure and the Homer City-Stolle Road 345-kV lines in Pennsylvania, that are not highly integrated into the electrical network, tripped quickly and split the grid between the sections that blacked out and those that recovered without further propagating the cascade. This same phenomenon was seen in the Pacific Northwest blackouts of 1996, when long lines tripped before more networked, electrically supported lines.

Transmission line voltage divided by its current flow is called "apparent impedance." Standard transmission line protective relays continuously measure apparent impedance. When apparent impedance drops within the line's protective relay set-points for a given period of time, the relays trip the line. The vast majority of trip operations on lines along the blackout boundaries between PJM and New York (for instance) show high-speed relay targets, which indicate that massive power surges caused each line to trip. To the relays, this massive power surge altered the voltages and currents enough that they appeared to be faults. This power surge was caused by power flowing to those areas that were generation-deficient. These flows occurred purely because of the physics of power flows, with no regard to whether the power flow had been scheduled, because power flows from areas with excess generation into areas that are generation-deficient.

Relative voltage levels across the northeast affected which areas blacked out and which areas stayed on-line. Within the Midwest, there were relatively low reserves of reactive power, so as voltage levels declined many generators in the affected area were operating at maximum reactive power output before the blackout. This left the system little slack to deal with the low voltage conditions by ramping up more generators to higher reactive power output levels, so there was little room to absorb any system "bumps" in voltage or frequency. In contrast, in the northeast—particularly PJM, New York, and ISO-New England—operators were anticipating high power demands on the afternoon of August 14, and had already set up the system to maintain higher voltage levels and therefore had more reactive reserves on-line in anticipation of later afternoon needs. Thus, when the voltage and frequency swings began, these systems had reactive power already or readily available to help buffer their areas against a voltage collapse without widespread generation trips.

Figure 5.16. Cascade Sequence



Legend: Yellow arrows represent the overall pattern of electricity flows. Black lines represent approximate points of separation between areas within the Eastern Interconnect. Gray shading represents areas affected by the blackout.

Voltage Collapse

Although the blackout of August 14 has been labeled as a voltage collapse, it was not a voltage collapse as that term has been traditionally used by power system engineers. Voltage collapse typically occurs on power systems that are heavily loaded, faulted (reducing the number of available paths for power to flow to loads), or have reactive power shortages. The collapse is initiated when reactive power demands of loads can no longer be met by the production and transmission of reactive power. A classic voltage collapse occurs when an electricity system experiences a disturbance that causes a progressive and uncontrollable decline in voltage. Dropping voltage causes a further reduction in reactive power from capacitors and line charging, and still further voltage reductions. If the collapse continues, these voltage reductions cause additional elements to trip, leading to further reduction in voltage and loss of load. At some point the voltage may stabilize but at a much reduced level. In summary, the system begins to fail due to inadequate reactive power supplies rather than due to overloaded facilities.

On August 14, the northern Ohio electricity system did not experience a classic voltage collapse because low voltage never became the primary cause of line and generator tripping. Although voltage was a factor in some of the events that led to the ultimate cascading of the system in Ohio and beyond, the event was not a classic reactive power-driven voltage collapse. Rather, although reactive power requirements were high, voltage levels were within acceptable bounds before individual transmission trips began, and a shortage of reactive power did not trigger the collapse. Voltage levels began to degrade, but not collapse, as early transmission lines were lost due to tree-line contacts causing ground faults. With fewer lines operational, current flowing over the remaining lines increased and voltage decreased (current increases in inverse proportion to the decrease in voltage for a given amount of power flow). Soon, in northern Ohio, lines began to trip out automatically on protection from overloads, rather than from insufficient reactive power. As the cascade spread beyond Ohio, it spread due not to insufficient reactive power, but because of dynamic power swings and the resulting system instability.

On August 14, voltage collapse in some areas was a result, rather than a cause, of the cascade. Significant voltage decay began after the system was already in an N-3 or N-4 contingency situation. Frequency plots over the course of the cascade show areas with too much generation and others with too much load as the system attempted to reach equilibrium between generation and load. As the transmission line failures caused load to drop off, some parts of the system had too much generation, and some units tripped off on over-frequency protection. Frequency fell, more load dropped on under-frequency protection, the remaining generators sped up and then some of them tripped off, and so on. For a period, conditions see-sawed across the northeast, ending with isolated pockets in which generation and load had achieved balance, and wide areas that had blacked out before an equilibrium had been reached.

Why the Generators Tripped Off

At least 263 power plants with more than 531 individual generating units shut down in the August 14 blackout. These U.S. and Canadian plants can be categorized as follows:

By reliability coordination area:

- Hydro Quebec, 5 plants
- Ontario, 92 plants
- ISO-New England, 31 plants
- MISO, 30 plants
- New York ISO, 67 plants
- PJM, 38 plants

By type:

- Conventional steam units, 67 plants (39 coal)
- Combustion turbines, 66 plants (36 combined cycle)
- Nuclear, 10 plants—7 U.S. and 3 Canadian, totaling 19 units (the nuclear unit outages are discussed in Chapter 7)
- Hydro, 101
- Other, 19

There were three categories of generator shutdowns:

1. Excitation system failures during extremely low voltage conditions on portions of the power system
2. Plant control system actions after major disturbances to in-plant thermal/mechanical systems
3. Consequential tripping due to total system disconnection or collapse.

Examples of the three types of separation are discussed below.

Excitation failures. The Eastlake 5 trip at 1:31 p.m. was an excitation system failure—as voltage fell at the generator bus, the generator tried to increase its production of voltage on the coil (excitation) quickly. This caused the generator's excitation protection scheme to trip the plant off to protect its windings and coils from over-heating. Several of the other generators which tripped early in the cascade came off under similar circumstances as excitation systems were over-stressed to hold voltages up.

After the cascade was initiated, huge power swings across the torn transmission system and excursions of system frequency put all the units in their path through a sequence of major disturbances that shocked several units into tripping. Plant controls had actuated fast governor action on several of these to turn back the throttle, then turn it forward, only to turn it back again as some frequencies changed several times by as much as 3 Hz (about 100 times normal). Figure 5.17 is a plot of the MW output and frequency for one large unit that nearly survived the disruption but tripped when in-plant hydraulic control pressure limits were eventually violated. After the plant control system called for shutdown, the turbine control valves closed and the generator electrical output ramped down to a preset value before the field excitation tripped and the generator breakers opened to disconnect the unit from the system.

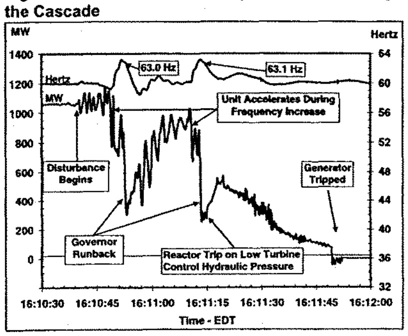
Plant control systems. The second reason for power plant trips was actions or failures of plant control systems. One common cause in this category was a loss of sufficient voltage to in-plant loads. Some plants run their internal cooling and processes (house electrical load) off the generator or off small, in-house auxiliary generators, while others take their power off the main grid. When large power swings or voltage drops reached these plants in the latter category, they tripped off-line because the grid could not supply the plant's in-house power needs reliably.

Consequential trips. Most of the unit separations fell in the third category of consequential tripping—they tripped off-line in response to some outside condition on the grid, not because of any problem internal to the plant. Some generators became completely removed from all loads; because the fundamental operating principle of the grid is that load and generation must balance, if there was no load to be served the power plant shut down in response to over-speed and/or over-voltage protection schemes. Others were overwhelmed because they were among a few power plants within an electrical island, and were suddenly called on to serve huge customer loads, so the imbalance caused them to trip on under-frequency and/or under-voltage protection. A few were tripped by special protection schemes that activated on excessive frequency or loss of pre-studied major transmission elements known to require large blocks of generation rejection.

The maps in Figure 5.18 show the sequence of power plants lost in three blocks of time during the cascade.

The investigation team is still analyzing data on the effect of the cascade on the affected generators, to learn more about how to protect generation and transmission assets and speed system restoration in the future.

Figure 5.17. Events at One Large Generator During the Cascade

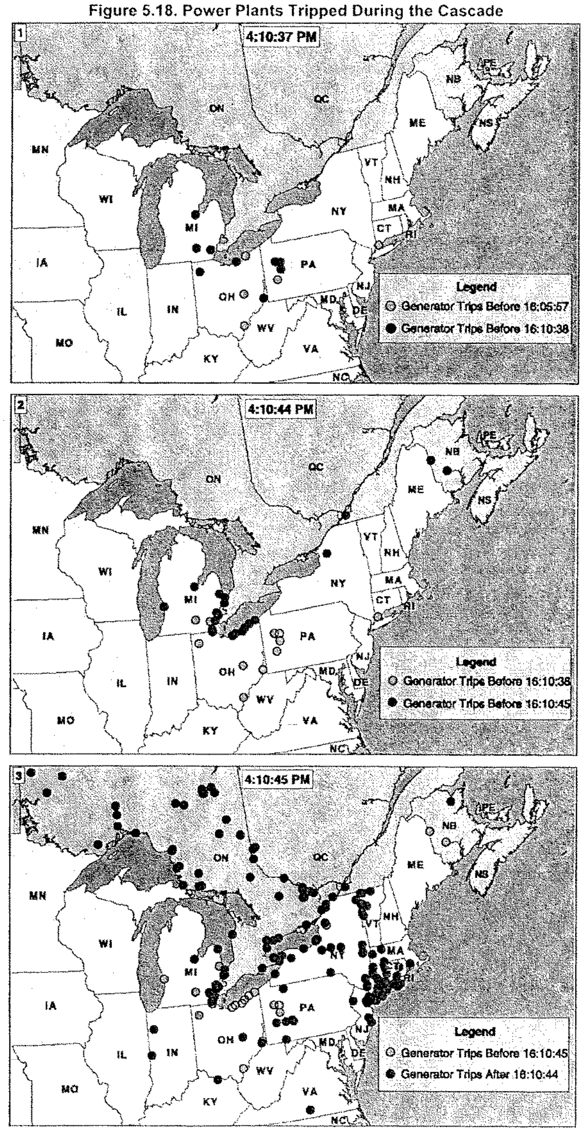


Endnotes

[1] The extensive computer modeling required to determine the expansion and cessation of the blackout (line by line, relay by relay, generator by generator, etc.) has not been performed.

[2] After New England's separation from the Eastern Interconnection occurred, the next several minutes were critical to stabilizing the ISO-NE system. Voltages in New England recovered and over-shot to high due to the combination of load loss, capacitors still in service, lower reactive losses on the transmission system, and loss of generation to regulate system voltage. Over-voltage protective relays operated to trip both transmission and distribution capacitors. Operators in New England brought all fast-start generation on-line by 16:16 EDT. Much of the customer process load was automatically restored. This caused voltages to drop again, putting portions of New England at risk of voltage collapse. Operators manually dropped 80 MW of load in southwest Connecticut by 16:39 EDT, another 325 MW in Connecticut and 100 MW in western Massachusetts by 16:40 EDT. These measures helped to stabilize their island following their separation from the rest of the Eastern Interconnection.

Figure 5.18. Power Plants Tripped During the Cascade



6. The August 14 Blackout Compared With Previous Major North American Outages

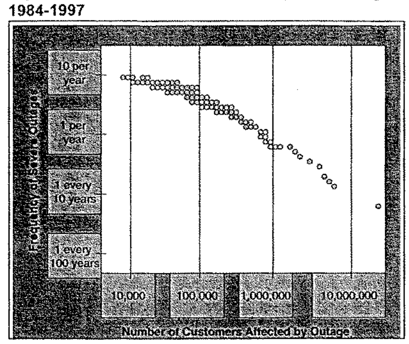
Incidence and Characteristics of Power System Outages

Short, localized outages occur on power systems fairly frequently. System-wide disturbances that affect many customers across a broad geographic area are rare, but they occur more frequently than a normal distribution of probabilities would predict. North American power system outages between 1984 and 1997 are shown in Figure 6.1 by the number of customers affected and the rate of occurrence. While some of these were widespread weather-related events, some were cascading events that, in retrospect, were preventable. Electric power systems are fairly robust and are capable of withstanding one or two contingency events, but they are fragile with respect to multiple contingency events unless the systems are readjusted between contingencies. With the shrinking margin in the current transmission system, it is likely to be more vulnerable to cascading outages than it was in the past, unless effective countermeasures are taken.

As evidenced by the absence of major transmission projects undertaken in North America over the past 10 to 15 years, utilities have found ways to increase the utilization of their existing facilities to meet increasing demands without adding significant high-voltage equipment. Without intervention, this trend is likely to continue. Pushing the system harder will undoubtedly increase reliability challenges. Special protection schemes may be relied on more to deal with particular challenges, but the system still will be less able to withstand unexpected contingencies.

A smaller transmission margin for reliability makes the preservation of system reliability a harder job than it used to be. The system is being operated closer to the edge of reliability than it was just a few years ago. Table 6.1 represents some of the changed conditions that make the preservation of reliability more challenging.

Figure 6.1. North American Power System Outages, 1984-1997



Note: The bubbles represent individual outages in North America between 1984 and 1997.

Source: Adapted from John Doyle, California Institute of Technology, "Complexity and Robustness," 1999. Data from NERC.

If nothing else changed, one could expect an increased frequency of large-scale events as compared to historical experience. The last and most extreme event shown in Figure 6.1 is the August 10, 1996, outage. August 14, 2003, surpassed that event in terms of severity. In addition, two significant outages in the month of September 2003 occurred abroad: one in England and one, initiated in Switzerland, that cascaded over much of Italy.

In the following sections, seven previous outages are reviewed and compared with the blackout of August 14, 2003: (1) Northeast blackout on November 9, 1965; (2) New York City blackout on July 13, 1977; (3) West Coast blackout on December 22, 1982; (4) West Coast blackout on July 2-3, 1996; (5) West Coast blackout on August 10, 1996; (6) Ontario and U.S. North Central blackout on June 25, 1998; and (7) Northeast outages and non-outage disturbances in the summer of 1999.

Outage Descriptions and Major Causal Factors

November 9, 1965: Northeast Blackout

This disturbance resulted in the loss of over 20,000 MW of load and affected 30 million people. Virtually all of New York, Connecticut, Massachusetts, Rhode Island, small segments of northern Pennsylvania and northeastern New Jersey, and substantial areas of Ontario, Canada, were affected. Outages lasted for up to 13 hours. This event resulted in the formation of the North American Electric Reliability Council in 1968.

A backup protective relay operated to open one of five 230-kV lines taking power north from a generating plant in Ontario to the Toronto area. When the flows redistributed instantaneously to the remaining four lines, they tripped out successively in a total of 2.5 seconds. The resultant power swings resulted in a cascading outage that blacked out much of the Northeast.

The major causal factors were as follows:

- Operation of a backup protective relay took a 230-kV line out of service when the loading on the line exceeded the 375-MW relay setting.
- Operating personnel were not aware of the operating set point of this relay.
- Another 230-kV line opened by an overcurrent relay action, and several 115- and 230-kV lines opened by protective relay action.
- Two key 345-kV east-west (Rochester-Syracuse) lines opened due to instability, and several lower voltage lines tripped open.
- Five of 16 generators at the St. Lawrence (Massena) plant tripped automatically in accordance with predetermined operating procedures.
- Following additional line tripouts, 10 generating units at Beck were automatically shut down by low governor oil pressure, and 5 pumping generators were tripped off by overspeed governor control.
- Several other lines then tripped out on under-frequency relay action.

July 13, 1977: New York City Blackout

This disturbance resulted in the loss of 6,000 MW of load and affected 9 million people in New York City. Outages lasted for up to 26 hours. A series of events triggering the separation of the Consolidated Edison system from neighboring systems and its subsequent collapse began when two 345-kV lines on a common tower in Northern Westchester were struck by lightning and tripped out. Over the next hour, despite Consolidated Edison dispatcher actions, the system electrically separated from surrounding systems and collapsed. With the loss of imports, generation in New York City was not sufficient to serve the load in the city.

Major causal factors were:

Table 6.1. Changing Conditions That Affect System Reliability

Previous Conditions	Emerging Conditions
Fewer, relatively large resources	Smaller, more numerous resources
Long-term, firm contracts	Contracts shorter in duration More non-firm transactions, fewer long-term firm transactions
Bulk power transactions relatively stable and predictable	Bulk power transactions relatively variable and less predictable
Assessment of system reliability made from stable base (narrower, more predictable range of potential operating states)	Assessment of system reliability made from variable base (wider, less predictable range of potential operating states)
Limited and knowledgable set of utility players	More players making more transactions, some with less interconnected operation experience; increasing with retail access
Unused transmission capacity and high security margins	High transmission utilization and operation closer to security limits
Limited competition, little incentive for reducing reliability investments	Utilities less willing to make investments in transmission reliability that do not increase revenues
Market rules and reliability rules developed together	Market rules undergoing transition, reliability rules developed separately
Limited wheeling	More system throughput

- Two 345-kV lines connecting Buchanan South to Millwood West were subjected to a phase B to ground fault caused by a lightning strike.
- Circuit breaker operations at the Buchanan South ring bus isolated the Indian Point No. 3 generating unit from any load, and the unit tripped for a rejection of 883 MW of load.
- Loss of the ring bus isolated the 345-kV tie to Ladentown, which had been importing 427 MW, making the cumulative load loss 1,310 MW.
- 18.5 minutes after the first incident, an additional lightning strike caused the loss of two 345-kV lines, which connect Sprain Brook to Buchanan North and Sprain Brook to Millwood West. These two 345-kV lines share common towers between Millwood West and Sprain Brook. One line (Sprain Brook to Millwood West) automatically reclosed and was restored to service in about 2 seconds. The failure of the other line to reclose isolated the last Consolidated Edison interconnection to the Northwest.
- The resulting surge of power from the Northwest caused the loss of the Pleasant Valley to Millwood West line by relay action (a bent contact on one of the relays at Millwood West caused the improper action).
- 23 minutes later, the Leeds to Pleasant Valley 345-kV line sagged into a tree due to overload and tripped out.
- Within a minute, the 345 kV to 138 kV transformer at Pleasant Valley overloaded and tripped off, leaving Consolidated Edison with only three remaining interconnections.
- Within 3 minutes, the Long Island Lighting Co. system operator, on concurrence of the pool dispatcher, manually opened the Jamaica to Valley Stream tie.
- About 7 minutes later, the tap-changing mechanism failed on the Goethals phase-shifter, resulting in the loss of the Linden to Goethals tie to PJM, which was carrying 1,150 MW to Consolidated Edison.
- The two remaining external 138-kV ties to Consolidated Edison tripped on overload, isolating the Consolidated Edison system.
- Insufficient generation in the isolated system caused the Consolidated Edison island to collapse.

December 22, 1982: West Coast Blackout

This disturbance resulted in the loss of 12,350 MW of load and affected over 5 million people in the West. The outage began when high winds caused the failure of a 500-kV transmission tower. The tower fell into a parallel 500-kV line tower, and both lines were lost. The failure of these two lines mechanically cascaded and caused three additional towers to fail on each line. When the line conductors fell they contacted two 230-kV lines crossing under the 500-kV rights-of-way, collapsing the 230-kV lines.

The loss of the 500-kV lines activated a remedial action scheme to control the separation of the interconnection into two pre-engineered islands and trip generation in the Pacific Northwest in order to minimize customer outages and speed restoration. However, delayed operation of the remedial action scheme components occurred for several reasons, and the interconnection separated into four islands.

In addition to the mechanical failure of the transmission lines, analysis of this outage cited problems with coordination of protective schemes, because the generator tripping and separation schemes operated slowly or did not operate as planned. A communication channel component performed sporadically, resulting in delayed transmission of the control signal. The backup separation scheme also failed to operate, because the coordination of relay settings did not anticipate the power flows experienced in this severe disturbance.

In addition, the volume and format in which data were displayed to operators made it difficult to assess the extent of the disturbance and what corrective action should be taken. Time references to events in this disturbance were not tied to a common standard, making real-time evaluation of the situation more difficult.

July 2-3, 1996: West Coast Blackout

This disturbance resulted in the loss of 11,850 MW of load and affected 2 million people in the West. Customers were affected in Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming in the United States; Alberta and British Columbia in Canada; and Baja California Norte in Mexico. Outages lasted from a few minutes to several hours.

The outage began when a 345-kV transmission line in Idaho sagged into a tree and tripped out. A protective relay on a parallel transmission line also detected the fault and incorrectly tripped a second line. An almost simultaneous loss of these lines greatly reduced the ability of the system to transmit power from the nearby Jim Bridger plant. Other relays tripped two of the four generating units at that plant. With the loss of those two units, frequency in the entire Western Interconnection began to decline, and voltage began to collapse in the Boise, Idaho, area, affecting the California-Oregon AC Intertie transfer limit.

For 23 seconds the system remained in precarious balance, until the Mill Creek to Antelope 230-kV line between Montana and Idaho tripped by zone 3 relay, depressing voltage at Summer Lake Substation and causing the intertie to slip out of synchronism. Remedial action relays separated the system into five pre-engineered islands designed to minimize customer outages and restoration times. Similar conditions and initiating factors were present on July 3; however, as voltage began to collapse in the Boise area, the operator shed load manually and contained the disturbance.

August 10, 1996: West Coast Blackout

This disturbance resulted in the loss of over 28,000 MW of load and affected 7.5 million people in the West. Customers were affected in Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming in the United States; Alberta and British Columbia in Canada; and Baja California Norte in Mexico. Outages lasted from a few minutes to as long as 9 hours.

Triggered by several major transmission line outages, the loss of generation from McNary Dam, and resulting system oscillations, the Western Interconnection separated into four electrical islands, with significant loss of load and generation. Prior to the disturbance, the transmission system from Canada south through the Northwest into California was heavily loaded with north-to-south power transfers. These flows were due to high Southwest demand caused by hot weather, combined with excellent hydroelectric conditions in Canada and the Northwest.

Very high temperatures in the Northwest caused two lightly loaded transmission lines to sag into untrimmed trees and trip out. A third heavily loaded line also sagged into a tree. Its outage led to the overload and loss of additional transmission lines. General voltage decline in the Northwest and the loss of McNary generation due to incorrectly applied relays caused power oscillations on the California to Oregon AC intertie. The intertie's protective relays tripped these facilities out and caused the Western Interconnection to separate into four islands. Following the loss of the first two lightly loaded lines, operators were unaware that the system was in an insecure state over the next hour, because new operating studies had not been performed to identify needed system adjustment.

June 25, 1998: Ontario and U.S. North Central Blackout

This disturbance resulted in the loss of 950 MW of load and affected 152,000 people in Minnesota, Montana, North Dakota, South Dakota, and Wisconsin in the United States; and Ontario, Manitoba, and Saskatchewan in Canada. Outages lasted up to 19 hours.

A lightning storm in Minnesota initiated a series of events, causing a system disturbance that affected the entire Mid-Continent Area Power Pool (MAPP) Region and the northwestern Ontario Hydro system of the Northeast Power Coordinating Council. A 345-kV line was struck by lightning and tripped out. Underlying lower voltage lines began to overload and trip out, further weakening the system. Soon afterward, lightning struck a second 345-kV line, taking it out of service as well. Following the outage of the second 345-kV line, the remaining lower voltage transmission lines in the area became significantly overloaded, and relays took them out of service. This cascading removal of lines from service continued until the entire northern MAPP Region was separated from the Eastern Interconnection, forming three islands and resulting in the eventual blackout of the northwestern Ontario Hydro system.

Summer of 1999: Northeast U.S. Outages and Non-outage Disturbances

Load in the PJM system on July 6, 1999, was 51,600 MW (approximately 5,000 MW above forecast). PJM used all emergency procedures (including a 5% voltage reduction) except manually tripping load, and imported 5,000 MW from external systems to serve the record customer demand. Load on July 19, 1999, exceeded 50,500 MW. PJM loaded all available eastern PJM generation and again implemented PJM emergency operating procedures from approximately 12 noon into the evening on both days.

During record peak loads, steep voltage declines were experienced on the bulk transmission system. Emergency procedures were implemented to prevent voltage collapse. Low voltage occurred because reactive demand exceeded reactive supply. High reactive demand was due to high electricity demand and high losses resulting from high transfers across the system. Reactive supply was inadequate because generators were unavailable or unable to meet rated reactive capability due to ambient conditions, and because some shunt capacitors were out of service.

Common or Similar Factors Among Major Outages

Among the factors that were either common to the major outages above and the August 14 blackout or had similarities among the events are the following: (1) conductor contact with trees; (2) underestimation of dynamic reactive output of system generators; (3) inability of system operators or coordinators to visualize events on the entire system; (4) failure to ensure that system operation was within safe limits; (5) lack of coordination on system protection; (6) ineffective communication; (7) lack of "safety nets;" and (8) inadequate training of operating personnel. The following sections describe the nature of these factors and list recommendations from previous investigations that are relevant to each.

Conductor Contact With Trees

This factor was an initiating trigger in several of the outages and a contributing factor in the severity of several more. Unlike lightning strikes, for which system operators have fair storm-tracking tools, system operators generally do not have direct knowledge that a line has contacted a tree and faulted. They will sometimes test the line by trying to restore it to service, if that is deemed to be a safe operation. Even if it does go back into service, the line may fault and trip out again as load heats it up. This is most likely to happen when vegetation has not been adequately managed, in combination with hot and windless conditions.

In some of the disturbances, tree contact accounted for the loss of more than one circuit, contributing multiple contingencies to the weakening of the system. Lines usually sag into right-of-way obstructions when the need to retain transmission interconnection is significant. High inductive load composition, such as air conditioning or irrigation pumping, accompanies hot weather and places higher burdens on transmission lines. Losing circuits contributes to voltage decline. Inductive load is unforgiving when voltage declines, drawing additional reactive supply from the system and further contributing to voltage problems.

Recommendations from previous investigations include:

- Paying special attention to the condition of rights-of-way following favorable growing seasons. Very wet and warm spring and summer growing conditions preceded the 1996 outages in the West.
- Careful review of any reduction in operations and maintenance expenses that may contribute to decreased frequency of line patrols or trimming. Maintenance in this area should be strongly directed toward preventive rather than remedial maintenance.

Dynamic Reactive Output of Generators

Reactive supply is an important ingredient in maintaining healthy power system voltages and facilitating power transfers. Inadequate reactive supply was a factor in most of the events. Shunt capacitors and generating resources are the most significant suppliers of reactive power. Operators perform contingency analysis based on how power system elements will perform under various power system conditions. They determine and set transfer limits based on these analyses. Shunt capacitors are easy to model because they are static. Modeling the dynamic reactive output of generators under stressed system conditions has proven to be more challenging. If the model is incorrect, estimating transfer limits will also be incorrect.

In most of the events, the assumed contribution of dynamic reactive output of system generators was greater than the generators actually produced, resulting in more significant voltage problems. Some generators were limited in the amount of reactive power they produced by over-excitation limits, or necessarily derated because of high ambient temperatures. Other generators were controlled to a fixed power factor and did not contribute reactive supply in depressed voltage conditions. Under-voltage load shedding is employed as an automatic remedial action in some interconnections to prevent cascading.

Recommendations from previous investigations concerning voltage support and reactive power management include:

- Communicate changes to generator reactive capability limits in a timely and accurate manner for both planning and operational modeling purposes.
- Investigate the development of a generator MVAr/voltage monitoring process to determine when generators may not be following reported MVAr limits.
- Establish a common standard for generator steady-state and post-contingency (15-minute) MVAr capability definition; determine methodology, testing, and operational reporting requirements.
- Determine the generator service level agreement that defines generator MVAr obligation to help ensure reliable operations.
- Periodically review and field test the reactive limits of generators to ensure that reported MVAr limits are attainable.
- Provide operators with on-line indications of available reactive capability from each generating unit or groups of generators, other VAr sources, and the reactive margin at all critical buses. This information should assist in the operating practice of maximizing the use of shunt capacitors during heavy transfers and thereby increase the availability of system dynamic reactive reserve.
- For voltage instability problems, consider fast automatic capacitor insertion (both series and shunt), direct shunt reactor and load tripping, and under-voltage load shedding.
- Develop and periodically review a reactive margin against which system performance should be evaluated and used to establish maximum transfer levels.

System Visibility Procedures and Operator Tools

Each control area operates as part of a single synchronous interconnection. However, the parties with various geographic or functional responsibilities for reliable operation of the grid do not have visibility of the entire system. Events in neighboring systems may not be visible to an operator or reliability coordinator, or power system data may be available in a control center but not be presented to operators or coordinators as information they can use in making appropriate operating decisions.

Recommendations from previous investigations concerning visibility and tools include:

- Develop communications systems and displays that give operators immediate information on changes in the status of major components in their own and neighboring systems.
- Supply communications systems with uninterruptible power, so that information on system conditions can be transmitted correctly to control centers during system disturbances.
- In the control center, use a dynamic line loading and outage display board to provide operating personnel with rapid and comprehensive information about the facilities available and the operating condition of each facility in service.
- Give control centers the capability to display to system operators computer-generated alternative actions specific to the immediate situation, together with expected results of each action.
- Establish on-line security analysis capability to identify those next and multiple facility outages that would be critical to system reliability from thermal, stability, and post-contingency voltage points of view.
- Establish time-synchronized disturbance monitoring to help evaluate the performance of the interconnected system under stress, and design appropriate controls to protect it.

System Operation Within Safe Limits

Operators in several of the events were unaware of the vulnerability of the system to the next contingency. The reasons were varied: inaccurate modeling for simulation, no visibility of the loss of key transmission elements, no operator monitoring of stability measures (reactive reserve monitor, power transfer angle), and no reassessment of system conditions following the loss of an element and readjustment of safe limits.

Recommendations from previous investigations include:

- Following a contingency, the system must be returned to a reliable state within the allowed readjustment period. Operating guides must be reviewed to ensure that procedures exist to restore system reliability in the allowable time periods.

- ◆ Reduce scheduled transfers to a safe and prudent level until studies have been conducted to determine the maximum simultaneous transfer capability limits.
- ◆ Reevaluate processes for identifying unusual operating conditions and potential disturbance scenarios, and make sure they are studied before they are encountered in real-time operating conditions.

Coordination of System Protection (Transmission and Generation Elements)

Protective relays are designed to detect abnormal conditions and act locally to isolate faulted power system equipment from the system—both to protect the equipment from damage and to protect the system from faulty equipment. Relay systems are applied with redundancy in primary and backup modes. If one relay fails, another should detect the fault and trip appropriate circuit breakers. Some backup relays have significant "reach," such that non-faulted line overloads or stable swings may be seen as faults and cause the tripping of a line when it is not advantageous to do so. Proper coordination of the many relay devices in an interconnected system is a significant challenge, requiring continual review and revision. Some relays can prevent resynchronizing, making restoration more difficult.

System-wide controls protect the interconnected operation rather than specific pieces of equipment. Examples include controlled islanding to mitigate the severity of an inevitable disturbance and under-voltage or under-frequency load shedding. Failure to operate (or misoperation of) one or more relays as an event developed was a common factor in several of the disturbances.

Recommendations developed after previous outages include:

- ◆ Perform system trip tests of relay schemes periodically. At installation the acceptance test should be performed on the complete relay scheme in addition to each individual component so that the adequacy of the scheme is verified.
- ◆ Continually update relay protection to fit changing system development and to incorporate improved relay control devices.
- ◆ Install sensing devices on critical transmission lines to shed load or generation automatically if the short-term emergency rating is exceeded for a specified period of time. The time delay should be long enough to allow the system operator to attempt to reduce line loadings promptly by other means.
- ◆ Review phase-angle restrictions that can prevent reclosing of major interconnections during system emergencies. Consideration should be given to bypassing synchronism-check relays to permit direct closing of critical interconnections when it is necessary to maintain stability of the grid during an emergency.
- ◆ Review the need for controlled islanding. Operating guides should address the potential for significant generation/load imbalance within the islands.

Effectiveness of Communications

Under normal conditions, parties with reliability responsibility need to communicate important and prioritized information to each other in a timely way, to help preserve the integrity of the grid. This is especially important in emergencies. During emergencies, operators should be relieved of duties unrelated to preserving the grid. A common factor in several of the events described above was that information about outages occurring in one system was not provided to neighboring systems.

Need for Safety Nets

A safety net is a protective scheme that activates automatically if a pre-specified, significant contingency occurs. When activated, such schemes involve certain costs and inconvenience, but they can prevent some disturbances from getting out of control. These plans involve actions such as shedding load, dropping generation, or islanding, and in all cases the intent is to have a controlled outcome that is less severe than the likely uncontrolled outcome. If a safety net had not been taken out of service in the West in August 1996, it would have lessened the severity of the disturbance from 28,000 MW of load lost to less than 7,200 MW. (It has since been returned to service.) Safety nets should not be relied upon to establish transfer limits, however.

Previous recommendations concerning safety nets include:

- ◆ Establish and maintain coordinated programs of automatic load shedding in areas not so equipped, in order to prevent total loss of power in an area that has been separated from the main network and is deficient in generation. Load shedding should be regarded as an insurance program, however, and should not be used as a substitute for adequate system design.

- Install load-shedding controls to allow fast single-action activation of large-block load shedding by an operator.

Training of Operating Personnel

Operating procedures were necessary but not sufficient to deal with severe power system disturbances in several of the events. Enhanced procedures and training for operating personnel were recommended. Dispatcher training facility scenarios with disturbance simulation were suggested as well. Operators tended to reduce schedules for transactions but were reluctant to call for increased generation—or especially to shed load—in the face of a disturbance that threatened to bring the whole system down.

Previous recommendations concerning training include:

- Thorough programs and schedules for operator training and retraining should be vigorously administered.
- A full-scale simulator should be made available to provide operating personnel with "hands-on" experience in dealing with possible emergency or other system conditions.
- Procedures and training programs for system operators should include anticipation, recognition, and definition of emergency situations.
- Written procedures and training materials should include criteria that system operators can use to recognize signs of system stress and mitigating measures to be taken before conditions degrade into emergencies.
- Line loading relief procedures should not be relied upon when the system is in an insecure state, as these procedures cannot be implemented effectively within the required time frames in many cases. Other readjustments must be used, and the system operator must take responsibility to restore the system immediately.
- Operators' authority and responsibility to take immediate action if they sense the system is starting to degrade should be emphasized and protected.
- The current processes for assessing the potential for voltage instability and the need to enhance the existing operator training programs, operational tools, and annual technical assessments should be reviewed to improve the ability to predict future voltage stability problems prior to their occurrence, and to mitigate the potential for adverse effects on a regional scale.

Comparisons With the August 14 Blackout

The blackout on August 14, 2003, had several causes or contributory factors in common with the earlier outages, including:

- Inadequate vegetation management
- Failure to ensure operation within secure limits
- Failure to identify emergency conditions and communicate that status to neighboring systems
- Inadequate operator training
- Inadequate regional-scale visibility over the power system.

New causal features of the August 14 blackout include: inadequate interregional visibility over the power system; dysfunction of a control area's SCADA/EMS system; and lack of adequate backup capability to that system.

7. Performance of Nuclear Power Plants Affected by the Blackout

Summary

On August 14, 2003, the northeastern United States and Canada experienced a widespread electrical power outage affecting an estimated 50 million people. Nine U.S. nuclear power plants experienced rapid shutdowns (reactor trips) as a consequence of the power outage. Seven nuclear power plants in Canada operating at high power levels at the time of the event also experienced rapid shutdowns. Four other Canadian nuclear plants automatically disconnected from the grid due to the electrical transient but were able to continue operating at a reduced power level and were available to supply power to the grid as it was restored by the transmission system operators. Six nuclear plants in the United States and one in Canada experienced significant electrical disturbances but were able to continue generating electricity. Non-nuclear generating plants in both countries also tripped during the event. Numerous other nuclear plants observed disturbances on the electrical grid but continued to generate electrical power without interruption.

The Nuclear Working Group (NWG) is one of the three Working Groups created to support the U.S.-Canada Power System Outage Task Force. The NWG was charged with identifying all relevant actions by nuclear generating facilities in connection with the outage. Nils Diaz, Chairman of the U.S. Nuclear Regulatory Commission (NRC) and Linda Keen, President and CEO of the Canadian Nuclear Safety Commission (CNSC) are co-chairs of the Working Group, with other members appointed from various State and federal agencies.

During Phase I of the investigation, the NWG focused on collecting and analyzing data from each plant to determine what happened, and whether any activities at the plants caused or contributed to the power outage or involved a significant safety issue. To ensure accuracy, NWG members coordinated their efforts with the Electric System Working Group (ESWG) and the Security Working Group (SWG). NRC and CNSC staff developed a set of technical questions to obtain data from the owners or licensees of the nuclear power plants that would enable their staff to review the response of the nuclear plant systems in detail. The plant data was compared against the plant design to determine if the plant responses were as expected; if they appeared to cause the power outage or contributed to the spread of the outage; and if applicable safety requirements were met.

Having reviewed the operating data for each plant and the response of the nuclear power plants and their staff to the event, the NWG concludes the following:

- All the nuclear plants that shut down or disconnected from the grid responded automatically to grid conditions.
- All the nuclear plants responded in a manner consistent with the plant designs.
- Safety functions were effectively accomplished, and the nuclear plants that tripped were maintained in a safe shutdown condition until their restart.
- The nuclear power plants did not trigger the power system outage or inappropriately contribute to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions). Rather, they responded as anticipated in order to protect equipment and systems from the grid disturbances.
- **For nuclear plants in the United States:**
  - Fermi 2, Oyster Creek, and Perry tripped due to main generator trips, which resulted from voltage and frequency fluctuations on the grid. Nine Mile 1 tripped due to a main turbine trip due to frequency fluctuations on the grid.

- FitzPatrick and Nine Mile 2 tripped due to reactor trips, which resulted from turbine control system low pressure due to frequency fluctuations on the grid. Ginna tripped due to a reactor trip which resulted from a large loss of electrical load due to frequency fluctuations on the grid. Indian Point 2 and Indian Point 3 tripped due to a reactor trip on low flow, which resulted when low grid frequency tripped reactor coolant pumps.

- **For nuclear plants in Canada:**
  - At Bruce B and Pickering B, frequency and/or voltage fluctuations on the grid resulted in the automatic disconnection of generators from the grid. For those units that were successful in maintaining the unit generators operational, reactor power was automatically reduced.
  - At Darlington, load swing on the grid led to the automatic reduction in power of the four reactors. The generators were, in turn, automatically disconnected from the grid.
  - Three reactors at Bruce B and one at Darlington were returned to 60% power. These reactors were available to deliver power to the grid on the instructions of the transmission system operator.
  - Three units at Darlington were placed in a zero-power hot state, and four units at Pickering B and one unit at Bruce B were placed in a Guaranteed Shutdown State.

The licensees' return to power operation follows a deliberate process controlled by plant procedures and regulations. Equipment and process problems, whether existing prior to or caused by the event, would normally be addressed prior to restart. The NWG is satisfied that licensees took an appropriately conservative approach to their restart activities, placing a priority on safety.

- **For U.S. nuclear plants:** Ginna, Indian Point 2, Nine Mile 2, and Oyster Creek resumed electrical generation on August 17. FitzPatrick and Nine Mile 1 resumed electrical generation on August 18. Fermi 2 resumed electrical generation on August 20. Perry resumed electrical generation on August 21. Indian Point 3 resumed electrical generation on August 22. Indian Point 3 had equipment issues (failed splices in the control rod drive mechanism power system) that required repair prior to restart. Ginna submitted a special request for enforcement discretion from the NRC to permit mode changes and restart with an inoperable auxiliary feedwater pump. The NRC granted the request for enforcement discretion.

- **For Canadian nuclear plants:** The restart of the Canadian nuclear plants was carried out in accordance with approved Operating Policies and Principles. Three units at Bruce B and one at Darlington were resynchronized with the grid within 6 hours of the event. The remaining three units at Darlington were reconnected by August 17 and 18. Units 5, 6, and 8 at Pickering B and Unit 6 at Bruce B returned to service between August 22 and August 25.

The NWG has found no evidence that the shutdown of the nuclear power plants triggered the outage or inappropriately contributed to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions). All the nuclear plants that shut down or disconnected from the grid responded automatically to grid conditions. All the nuclear plants responded in a manner consistent with the plant designs. Safety functions were effectively accomplished, and the nuclear plants that tripped were maintained in a safe shutdown condition until their restart.

Additional details are available in the following sections. Due to the major design differences between nuclear plants in Canada and the United States, the decision was made to have separate sections for each country. This also facilitates the request by the nuclear regulatory agencies in both countries to have sections of the report that stand alone, so that they can also be used as regulatory documents.

Findings of the U.S. Nuclear Working Group

Summary

The U.S. NWG has found no evidence that the shutdown of the nine U.S. nuclear power plants triggered the outage, or inappropriately contributed to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions). All nine plants that experienced a reactor trip were responding to grid conditions. The severity of the grid transient caused generators, turbines, or reactor systems at the plants to reach a protective feature limit and actuate a plant shutdown. All nine plants tripped in response to those conditions in a manner consistent with the plant designs. The nine plants automatically shut down in a safe fashion to protect the plants from the grid transient. Safety functions were effectively accomplished with few problems, and the plants were maintained in a safe shutdown condition until their restart.

The nuclear power plant outages that resulted from the August 14, 2003, power outage were triggered by automatic protection systems for the reactors or turbine-generators, not by any manual operator actions. The NWG has received no information that points to operators deliberately shutting down nuclear units to isolate themselves from instabilities on the grid. In short, only automatic separation of nuclear units occurred.

Regarding the 95 other licensed commercial nuclear power plants in the United States: 4 were already shut down at the time of the power outage, one of which experienced a grid disturbance; 70 operating plants observed some level of grid disturbance but accommodated the disturbances and remained on line, supplying power to the grid; and 21 operating plants did not experience any grid disturbance.

Introduction

In response to the August 14 power outage, the United States and Canada established a joint Power System Outage Task Force. Although many non-nuclear power plants were involved in the power outage, concerns about the nuclear power plants are being specifically addressed by the NWG in supporting of the joint Task Force. The Task Force was tasked with answering two questions:

1. What happened on August 14, 2003, to cause the transmission system to fail resulting in the power outage, and why?
2. Why was the system not able to stop the spread of the outage?

The NRC, which regulates U.S. commercial nuclear power plants, has regulatory requirements for offsite power systems. These requirements address the number of offsite power sources and the ability to withstand certain transients. Offsite power is the normal source of alternating current (AC) power to the safety systems in the plants when the plant main generator is not in operation. The requirements also are designed to protect safety systems from potentially damaging variations (in voltage and frequency) in the supplied power. For loss of offsite power events, the NRC requires emergency generation (typically emergency diesel generators) to provide AC power to safety systems. In addition, the NRC provides oversight of the safety aspects of offsite power issues through its inspection program, by monitoring operating experience, and by performing technical studies.

Phase I: Fact Finding

Phase I of the NWG effort focused on collecting and analyzing data from each plant to determine what happened, and whether any activities at the plants caused or contributed to the power outage or its spread or involved a significant safety issue. To ensure accuracy, a comprehensive coordination effort is ongoing among the working group members and between the NWG, ESWG, and SWG.

The staff developed a set of technical questions to obtain data from the owners or licensees of the nuclear power plants that would enable them to review the response of the nuclear plant systems in detail. Two additional requests for more specific information were made for certain plants. The collection of information from U.S. nuclear power plants was gathered through the NRC regional offices, which had NRC resident inspectors at each plant obtain licensee information to answer the questions. General design information was gathered from plant-specific Updated Final Safety Analysis Reports and other documents.

Plant data were compared against plant designs by the NRC staff to determine whether the plant responses were as expected; whether they appeared to cause the power outage or contributed to the spread of the outage; and whether applicable safety requirements were met. In some cases supplemental questions were developed, and answers were obtained from the licensees to clarify the observed response of the plant. The NWG interfaced with the ESWG to validate some data and to obtain grid information, which contributed to the analysis. The NWG has identified relevant actions by nuclear generating facilities in connection with the power outage.

Typical Design, Operational, and Protective Features of U.S. Nuclear Power Plants

Nuclear power plants have a number of design, operational, and protective features to ensure that the plants operate safely and reliably. This section describes these features so as to provide a better understanding of how nuclear power plants interact with the grid and, specifically, how nuclear power plants respond to changing grid conditions. While the features described in this section are typical, there are differences in the design and operation of individual plants which are not discussed.

Design Features of Nuclear Power Plants

Nuclear power plants use heat from nuclear reactions to generate steam and use a single steam-driven turbine-generator (also known as the main generator) to produce electricity supplied to the grid.

Connection of the plant switchyard to the grid. The plant switchyard normally forms the interface between the plant main generator and the electrical grid. The plant switchyard has multiple transmission lines connected to the grid system to meet offsite power supply requirements for having reliable offsite power for the nuclear station under all operating and shutdown conditions. Each transmission line connected to the switchyard has dedicated circuit breakers, with fault sensors, to isolate faulted conditions in the switchyard or the connected transmission lines, such as phase-to-phase or phase-to-ground short circuits. The fault sensors are fed into a protection scheme for the plant switchyard that is engineered to localize any faulted conditions with minimum system disturbance.

Connection of the main generator to the switchyard. The plant main generator produces electrical power and transmits that power to the offsite transmission system. Most plants also supply power to the plant auxiliary buses for normal operation of the nuclear generating unit through the unit auxiliary transformer. During normal plant operation, the main generator typically generates electrical power at about 22 kV. The voltage is increased to match the switchyard voltage by the main transformers, and the power flows to the high voltage switchyard through two power circuit breakers.

Power supplies for the plant auxiliary buses. The safety-related and nonsafety auxiliary buses are normally lined up to receive power from the main generator auxiliary transformer, although some plants leave some of their auxiliary buses powered from a startup transformer (that is, from the offsite power distribution system). When plant power generation is interrupted, the power supply automatically transfers to the offsite power source (the startup transformer). If that is not supplying acceptable voltage, the circuit breakers to the safety-related buses open, and the buses are reenergized by the respective fast-starting emergency diesel generators. The nonsafety auxiliary buses will remain deenergized until offsite power is restored.

Operational Features of Nuclear Power Plants

Response of nuclear power plants to changes in switchyard voltage. With the main generator voltage regulator in the automatic mode, the generator will respond to an increase of switchyard voltage by reducing the generator field excitation current. This will result in a decrease of reactive power, normally measured as mega-volts-amperes-reactive (MVAR) from the generator to the switchyard and out to the surrounding grid, helping to control the grid voltage increase. With the main generator voltage regulator in the automatic mode, the generator will respond to a decrease of switchyard voltage by increasing the generator field excitation current. This will result in an increase of reactive power (MVAR) from the generator to the switchyard and out to the surrounding grid, helping to control the grid voltage decrease. If the switchyard voltage goes low enough, the increased generator field current could result in generator field overheating. Over-excitation protective circuitry is generally employed to prevent this from occurring. This protective circuitry may trip the generator to prevent equipment damage.

Under-voltage protection is provided for the nuclear power plant safety buses, and may be provided on nonsafety buses and at individual pieces of equipment. It is also used in some pressurized water reactor designs on reactor coolant pumps (RCPs) as an anticipatory loss of RCP flow signal.

Protective Features of Nuclear Power Plants

The main generator and main turbine have protective features, similar to fossil generating stations, which protect against equipment damage. In general, the reactor protective features are designed to protect the reactor fuel from damage and to protect the reactor coolant system from over-pressure or over-temperature transients. Some trip features also produce a corresponding trip in other components; for example, a turbine trip typically results in a reactor trip above a low power setpoint.

Generator protective features typically include over-current, ground detection, differential relays (which monitor for electrical fault conditions within a zone of protection defined by the location of the sensors, typically the main generator and all transformers connected directly to the generator output), electrical faults on the transformers connected to the generator, loss of the generator field, and a turbine trip. Turbine protective features typically include over-speed (usually set at 1980 rpm or 66 Hz), low bearing oil pressure, high bearing vibration, degraded condenser vacuum, thrust bearing failure, or generator trip. Reactor protective features typically include trips for overpower, abnormal pressure in the reactor coolant system, low reactor coolant system flow, low level in the steam generators or the reactor vessel, or a trip of the turbine.

Considerations on Returning a U.S. Nuclear Power Plant to Power Production After Switchyard Voltage Is Restored

The following are examples of the types of activities that must be completed before returning a nuclear power plant to power production following a loss of switchyard voltage.

- Switchyard voltage must be normal and stable from an offsite supply. Nuclear power plants are not designed for black-start capability (the ability to start up without external power).
- Plant buses must be energized from the switchyard and the emergency diesel generators restored to standby mode.
- Normal plant equipment, such as reactor coolant pumps and circulating water pumps, must be restarted.
- A reactor trip review report must be completed and approved by plant management, and the cause of the trip must be addressed.
- All plant technical specifications must be satisfied. Technical specifications are issued to each nuclear power plant as part of their license by the NRC. They dictate equipment which must be operable and process parameters which must be met to allow operation of the reactor. Examples of actions that were required following the events of August 14 include refilling the diesel fuel oil storage tanks, refilling the condensate storage tanks, establishing reactor coolant system forced flow, and cooling the suppression pool to normal operating limits. Surveillance tests must be completed as required by technical specifications (for example, operability of the low-range neutron detectors must be demonstrated).
- Systems must be aligned to support the startup.
- Pressures and temperatures for reactor startup must be established in the reactor coolant system for pressurized water reactors.
- A reactor criticality calculation must be performed to predict the control rod withdrawals needed to achieve criticality, where the fission chain reaction becomes self-sustaining due to the increased neutron flux. Certain neutron-absorbing fission products increase in concentration following a reactor trip (followed later by a decrease or decay). At pressurized water reactors, the boron concentration in the primary coolant must be adjusted to match the criticality calculation. Near the end of the fuel cycle, the nuclear power plant may not have enough boron adjustment or control rod worth available for restart until the neutron absorbers have decreased significantly (more than 24 hours after the trip).

It may require about a day or more before a nuclear power plant can restart following a normal trip. Plant trips are a significant transient on plant equipment, and some maintenance may be necessary before the plant can restart. When combined with the infrequent event of loss of offsite power, additional recovery actions will be required. Safety systems, such as emergency diesel generators and safety-related decay heat removal systems, must be restored to normal lineups. These additional actions would extend the time necessary to restart a nuclear plant from this type of event.

Summary of U.S. Nuclear Power Plant Response to and Safety During the August 14 Outage

The NWG's review has not identified any activity or equipment issues at nuclear power plants that caused the transient on August 14, 2003. Nine nuclear power plants tripped within about 60 seconds as a result of the grid disturbance. Additionally, many nuclear power plants experienced a transient due to this grid disturbance.

Nuclear Power Plants That Tripped

The trips at nine nuclear power plants resulted from the plant responses to the grid disturbances. Following the initial grid disturbances, voltages in the plant switchyard fluctuated and reactive power flows fluctuated. As the voltage regulators on the main generators attempted to compensate, equipment limits were exceeded and protective trips resulted. This happened at Fermi 2 and Oyster Creek. Fermi 2 tripped on a generator field protection trip. Oyster Creek tripped due to a generator trip on high ratio of voltage relative to the electrical frequency.

Also, as the balance between electrical generation and electrical load on the grid was disturbed, the electrical frequency began to fluctuate. In some cases the electrical frequency dropped low enough to actuate protective features. This happened at Indian Point 2, Indian Point 3, and Perry. Perry tripped due to a generator under-frequency trip signal. Indian Point 2 and Indian Point 3 tripped when the grid frequency dropped low enough to trip reactor coolant pumps, which actuated a reactor protective feature.

In other cases, the electrical frequency fluctuated and went higher than normal. Turbine control systems responded in an attempt to control the frequency. Equipment limits were exceeded as a result of the reaction of the turbine control systems to large frequency changes. This led to trips at FitzPatrick, Nine Mile 1, Nine Mile 2, and Ginna. FitzPatrick and Nine Mile 2 tripped on low pressure in the turbine hydraulic control oil system. Nine Mile 1 tripped on turbine light load protection. Ginna tripped due to conditions in the reactor following rapid closure of the turbine control valves in response to high frequency on the grid.

The Perry, Fermi 2, Oyster Creek, and Nine Mile 1 reactors tripped immediately after the generator tripped, although that is not apparent from the times below, because the clocks were not synchronized to the national time standard. The Indian Point 2 and 3, FitzPatrick, Ginna, and Nine Mile 2 reactors tripped before the generators. When the reactor trips first, there is generally a short time delay before the generator output breakers open. The electrical generation decreases rapidly to zero after the reactor trip. Table 7.1 provides the times from the data collected for the reactor trip times, and the time the generator output breakers opened (generator trip), as reported by the ESWG. Additional details on the plants that tripped are given below.

Fermi 2. Fermi 2 is located 25 miles northeast of Toledo, Ohio, in southern Michigan on Lake Erie. It was generating about 1,130 megawatts-electric (MWe) before the event. The reactor tripped due to a turbine trip. The turbine trip was likely the result of multiple generator field protection trips (over-excitation and loss of field) as the Fermi 2 generator responded to a series of rapidly changing transients prior to its loss. This is consistent with data that shows large swings of the Fermi 2 generator MVARs prior to its trip.

Offsite power was subsequently lost to the plant auxiliary buses. The safety buses were de-energized and automatically reenergized from the emergency diesel generators. The operators tripped one emergency diesel generator that was paralled to the grid for testing, after which it automatically loaded. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:22 EDT due to the loss of offsite power. Offsite power was restored to at least one safety bus at about 01:53 EDT on August 15. The following equipment problems were noted: the Combustion Turbine Generator (the alternate AC power source) failed to start from the control room; however, it was successfully started locally. In addition, the Spent Fuel Pool Cooling System was interrupted for approximately 26 hours and reached a maximum temperature of 130 degrees Fahrenheit (55 degrees Celsius). The main generator was reconnected to the grid at about 01:41 EDT on August 20.

FitzPatrick. FitzPatrick is located about 8 miles northeast of Oswego, NY, in northern New York on Lake Ontario. It was generating about 850 MWe before the event. The reactor tripped due to low pressure in the hydraulic system that controls the turbine control valves. Low pressure in this system typically indicates a large load reject, for

Table 7.1. U.S. Nuclear Plant Trip Times

Nuclear Plant	Reactor Trip[a]	Generator Trip[b]
Perry	16:10:25 EDT	16:10:42 EDT
Fermi 2	16:10:53 EDT	16:10:53 EDT
Oyster Creek . . .	16:10:58 EDT	16:10:57 EDT
Nine Mile 1	16:11 EDT	16:11:04 EDT
Indian Point 2 . .	16:11 EDT	16:11:09 EDT
Indian Point 3 . .	16:11 EDT	16:11:23 EDT
FitzPatrick	16:11:04 EDT	16:11:32 EDT
Ginna.	16:11:36 EDT	16:12:17 EDT
Nine Mile 2	16:11:48 EDT	16:11:52 EDT

[a]As determined from licensee data (which may not be synchronized to the national time standard).
[b]As reported by the Electrical System Working Group (synchronized to the national time standard).

which a reactor trip is expected. In this case the pressure in the system was low because the control system was rapidly manipulating the turbine control valves to control turbine speed, which was being affected by grid frequency fluctuations.

Immediately preceding the trip, both significant over-voltage and under-voltage grid conditions were experienced. Offsite power was subsequently lost to the plant auxiliary buses. The safety buses were deenergized and automatically reenergized from the emergency diesel generators.

The lowest emergency declaration, an Unusual Event, was declared at about 16:26 EDT due to the loss of offsite power. Decay heat removal systems maintained the cooling function for the reactor fuel. Offsite power was restored to at least one safety bus at about 23:07 EDT on August 14. The main generator was reconnected to the grid at about 06:10 EDT on August 18.

Ginna. Ginna is located 20 miles northeast of Rochester, NY, in northern New York on Lake Ontario. It was generating about 487 MWe before the event. The reactor tripped due to Over-Temperature-Delta-Temperature. This trip signal protects the reactor core from exceeding temperature limits. The turbine control valves closed down in response to the changing grid conditions. This caused a temperature and pressure transient in the reactor, resulting in an Over-Temperature-Delta-Temperature trip.

Offsite power was not lost to the plant auxiliary buses. In the operators' judgement, offsite power was not stable, so they conservatively energized the safety buses from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel. Offsite power was not lost, and stabilized about 50 minutes after the reactor trip.

The lowest emergency declaration, an Unusual Event, was declared at about 16:46 EDT due to the degraded offsite power. Offsite power was restored to at least one safety bus at about 21:08 EDT on August 14. The following equipment problems were noted: the digital feedwater control system behaved in an unexpected manner following the trip, resulting in high steam generator levels; there was a loss of RCP seal flow indication, which complicated restarting the pumps; and at least one of the power-operated relief valves experienced minor leakage following proper operation and closure during the transient. Also, one of the motor-driven auxiliary feedwater pumps was damaged after running with low flow conditions due to an improper valve alignment. The redundant pumps supplied the required water flow.

The NRC issued a Notice of Enforcement Discretion to allow Ginna to perform mode changes and restart the reactor with one auxiliary feedwater (AFW) pump inoperable. Ginna has two AFW pumps, one turbine-driven AFW pump, and two standby AFW pumps, all powered from safety-related buses. The main generator was reconnected to the grid at about 20:38 EDT on August 17.

Indian Point 2. Indian Point 2 is located 24 miles north of New York City on the Hudson River. It was generating about 990 MWe before the event. The reactor tripped due to loss of a reactor coolant pump that tripped because the auxiliary bus frequency fluctuations actuated the under-frequency relay, which protects against inadequate coolant flow through the reactor core. This reactor protection signal tripped the reactor, which resulted in turbine and generator trips.

The auxiliary bus experienced the under-frequency due to fluctuating grid conditions. Offsite power was lost to all the plant auxiliary buses. The safety buses were reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:25 EDT due to the loss of offsite power for more than 15 minutes. Offsite power was restored to at least one safety bus at about 20:02 EDT on August 14. The following equipment problems were noted: the service water to one of the emergency diesel generators developed a leak; a steam generator atmospheric dump valve did not control steam generator pressure in automatic and had to be shifted to manual; a steam trap associated with the turbine-driven AFW pump failed open, resulting in operators securing the turbine after 2.5 hours; loss of instrument air required operators to take manual control of charging and a letdown isolation occurred; and operators in the field could not use radios. The main generator was reconnected to the grid at about 12:58 EDT on August 17.

Indian Point 3. Indian Point 3 is located 24 miles north of New York City on the Hudson River. It was generating about 1,010 MWe before the event. The reactor tripped due to loss of a reactor coolant pump that tripped because the auxiliary bus frequency fluctuations actuated the underfrequency relay, which protects against inadequate coolant flow through the reactor core. This reactor protection signal tripped the reactor, which resulted in turbine and generator trips.

The auxiliary bus experienced the underfrequency due to fluctuating grid conditions. Offsite power was lost to all the plant auxiliary buses. The safety buses were reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:23 EDT due to the loss of offsite power for more than 15 minutes. Offsite power was restored to at least one safety bus at about 20:12 EDT on August 14. The following equipment problems were noted: a steam generator safety valve lifted below its desired setpoint and was gagged; loss of instrument air, including failure of the diesel backup compressor to start and failure of the backup nitrogen system, resulted in manual control of atmospheric dump valves and AFW pumps needing to be secured to prevent overfeeding the steam generators; a blown fuse in a battery charger resulted in a longer battery discharge; a control rod drive mechanism cable splice failed, and there were high resistance readings on 345-kV breaker-1. These equipment problems required correction prior to start-up, which delayed the startup. The main generator was reconnected to the grid at about 05:03 EDT on August 22.

Nine Mile 1. Nine Mile 1 is located 6 miles northeast of Oswego, NY, in northern New York on Lake Ontario. It was generating about 600 MWe before the event. The reactor tripped in response to a turbine trip. The turbine tripped on light load protection (which protects the turbine against a loss of electrical load), when responding to fluctuating grid conditions. The turbine trip caused fast closure of the turbine valves, which, through acceleration relays on the control valves, create a signal to trip the reactor. After a time delay of 10 seconds, the generator tripped on reverse power.

The safety buses were automatically deenergized due to low voltage and automatically reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:33 EDT due to the degraded offsite power. Offsite power was restored to at least one safety bus at about 23:39 EDT on August 14. The following additional equipment problems were noted: a feedwater block valve failed "as is" on the loss of voltage, resulting in a high reactor vessel level; fuses blew in fire circuits, causing control room ventilation isolation and fire panel alarms; and operators were delayed in placing shutdown cooling in service for several hours due to lack of procedure guidance to address particular plant conditions encountered during the shutdown. The main generator was reconnected to the grid at about 02:08 EDT on August 18.

Nine Mile 2. Nine Mile 2 is located 6 miles northeast of Oswego, NY, in northern New York on Lake Ontario. It was generating about 1,193 MWe before the event. The reactor scrammed due to the actuation of pressure switches which detected low pressure in the hydraulic system that controls the turbine control valves. Low pressure in this system typically indicates a large load reject, for which a reactor trip is expected. In this case the pressure in the system was low because the control system was rapidly manipulating the turbine control valves to control turbine speed, which was being affected by grid frequency fluctuations.

After the reactor tripped, several reactor level control valves did not reposition, and with the main feedwater system continuing to operate, a high water level in the reactor caused a turbine trip, which caused a generator trip. Offsite power was degraded but available to the plant auxiliary buses. The offsite power dropped below the normal voltage levels, which resulted in the safety buses being automatically energized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 17:00 EDT due to the loss of offsite power to the safety buses for more than 15 minutes. Offsite power was restored to at least one safety bus at about 01:33 EDT on August 15. The following additional equipment problem was noted: a tap changer on one of the offsite power transformers failed, complicating the restoration of one division of offsite power. The main generator was reconnected to the grid at about 19:34 EDT on August 17.

Oyster Creek. Oyster Creek is located 9 miles south of Toms River, NJ, near the Atlantic Ocean. It was generating about 629 MWe before the event.

The reactor tripped due to a turbine trip. The turbine trip was the result of a generator trip due to actuation of a high Volts/Hz protective trip. The Volts/Hz trip is a generator/transformer protective feature. The plant safety and auxiliary buses transferred from the main generator supply to the offsite power supply following the plant trip. Other than the plant transient, no equipment or performance problems were determined to be directly related to the grid problems.

Post-trip the operators did not get the mode switch to shutdown before main steam header pressure reached its isolation setpoint. The resulting MSIV closure complicated the operator's response because the normal steam path to the main condenser was lost. The operators used the isolation condensers for decay heat removal. The plant safety and auxiliary buses remained energized from offsite power for the duration of the event, and the emergency diesel generators were not started. Decay heat removal systems maintained the cooling function for the reactor fuel. The main generator was reconnected to the grid at about 05:02 EDT on August 17.

Perry. Perry is located 7 miles northeast of Painesville, OH, in northern Ohio on Lake Erie. It was generating about 1,275 MWe before the event. The reactor tripped due to a turbine control valve fast closure trip signal. The turbine control valve fast closure trip signal was due to a generator under-frequency trip signal that tripped the generator and the turbine and was triggered by grid frequency fluctuations. Plant operators noted voltage fluctuations and spikes on the main transformer, and the Generator Out-of-Step Supervisory relay actuated approximately 30 minutes before the trip. This supervisory relay senses a ground fault on the grid. The purpose is to prevent a remote fault on the grid from causing a generator out-of-step relay to activate, which would result in a generator trip. Approximately 30 seconds prior to the trip operators noted a number of spikes on the generator field volt meter, which subsequently went offscale high. The MVAR and MW meters likewise went offscale high.

The safety buses were deenergized and automatically reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel. The following equipment problems were noted: a steam bypass valve opened; a reactor water clean-up system pump tripped; the off-gas system isolated, and a keep-fill pump was found to be air-bound, requiring venting and filling before the residual heat removal system loop A and the low pressure core spray system could be restored to service.

The lowest emergency declaration, an Unusual Event, was declared at about 16:20 EDT due to the loss of offsite power. Offsite power was restored to at least one safety bus at about 18:13 EDT on August 14. The main generator was reconnected to the grid at about 23:15 EDT on August 21. After the plant restarted, a surveillance test indicated a problem with one emergency diesel generator. An NRC special inspection is in progress, reviewing emergency diesel generator performance and the keep-fill system.

Nuclear Power Plants With a Significant Transient

The electrical disturbance on August 14 had a significant impact on seven plants that continued to remain connected to the grid. For this review, significant impact means that these plants had significant load adjustments that resulted in bypassing steam from the turbine generator, opening of relief valves, or requiring the onsite emergency diesel generators to automatically start due to low voltage.

Nuclear Power Plants With a Non-Significant Transient

Sixty-four nuclear power plants experienced non-significant transients caused by minor disturbances on the electrical grid. These plants were able to respond to the disturbances through normal control systems. Examples of these transients included changes in load of a few megawatts or changes in frequency of a few-tenths Hz.

Nuclear Power Plants With No Transient

Twenty-four nuclear power plants experienced no transient and saw essentially no disturbances on the grid, or were shut down at the time of the transient.

General Observations Based on the Facts Found During Phase One

The NWG has found no evidence that the shutdown of U.S. nuclear power plants triggered the outage or inappropriately contributed to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions). This review did not identify any activity or equipment issues that appeared to start the transient on August 14, 2003. All nine plants that experienced a reactor trip were responding to grid conditions. The severity of the transient caused generators, turbines, or reactor systems to reach a protective feature limit and actuate a plant shutdown.

All nine plants tripped in response to those conditions in a manner consistent with the plant designs. All nine plants safely shut down. All safety functions were effectively accomplished, with few problems, and the plants were maintained in a safe shutdown condition until their restart. Fermi 2, Nine Mile 1, Oyster Creek, and Perry tripped on turbine and generator protective features. FitzPatrick, Ginna, Indian Point 2 and 3, and Nine Mile 2 tripped on reactor protective features.

Nine plants used their emergency diesel generators to power their safety-related buses during the power outage. Offsite power was restored to the safety buses after the grid was energized and the plant operators, in consultation with the transmission system operators, decided the grid was stable. Although the Oyster Creek plant tripped, offsite power was never lost to their safety buses and the emergency diesel generators did not start and were not required. Another plant, Davis-Besse, was already shut down but lost power to the safety buses. The emergency diesel generators started and provided power to the safety buses as designed.

For the eight remaining tripped plants and Davis-Besse (which was already shut down prior to the events of August 14), offsite power was restored to at least one safety bus after a period of time ranging from about 2 hours to about 14 hours, with an average time of about 7 hours. Although Ginna did not lose offsite power, the operators judged offsite power to be unstable and realigned the safety buses to the emergency diesel generators. The second phase of the Power System Outage Task Force will consider the implications of this in developing recommendations for future improvements.

The licensees' return to power operation follows a deliberate process controlled by plant procedures and NRC regulations. Ginna, Indian Point 2, Nine Mile 2, and Oyster Creek resumed electrical generation on August 17. FitzPatrick and Nine Mile 1 resumed electrical generation on August 18. Fermi 2 resumed electrical generation on August 20. Perry resumed electrical generation on August 21. Indian Point 3 resumed electrical generation on August 22. Indian Point 3 had equipment issues (failed splices in the control rod drive mechanism power system) that required repair prior to restart. Ginna submitted a special request for enforcement discretion from the NRC to permit mode changes and restart with an inoperable auxiliary feedwater pump. The NRC granted the request for enforcement discretion.

Findings of the Canadian Nuclear Working Group

Summary

On the afternoon of August 14, 2003, southern Ontario, along with the northeastern United States, experienced a widespread electrical power system outage. Eleven nuclear power plants in Ontario operating at high power levels at the time of the event either automatically shut down as a result of the grid disturbance or automatically reduced power while waiting for the grid to be reestablished. In addition, the Point Lepreau Nuclear Generating Station in New Brunswick was forced to reduce electricity production for a short period.

The Canadian NWG was mandated to: review the sequence of events for each Canadian nuclear plant; determine whether any events caused or contributed to the power system outage; evaluate any potential safety issues arising as a result of the event; evaluate the effect on safety and the reliability of the grid of design features, operating procedures, and regulatory requirements at Canadian nuclear power plants; and assess the impact of associated regulator performance and regulatory decisions.

In Ontario, 11 nuclear units were operating and delivering power to the grid at the time of the grid disturbance: 4 at Bruce B, 4 at Darlington, and 3 at Pickering B. Of the 11 reactors, 7 shut down as a result of the event (1 at Bruce B, 3 at Darlington, and 3 at Pickering B). Four reactors (3 at Bruce B and 1 at Darlington) disconnected safely from the grid but were able to avoid shutting down and were available to supply power to the Ontario grid as soon as reconnection was enabled by Ontario's Independent Market Operator (IMO).

New Brunswick Power's Point Lepreau Generating Station responded to the loss of grid event by cutting power to 460 MW, returning to fully stable conditions at 16:35 EDT, within 25 minutes of the event. Hydro Québec's (HQ) grid was not affected by the power system outage, and HQ's Gentilly-2 nuclear station continued to operate normally.

Having reviewed the operating data for each plant and the responses of the power stations and their staff to the event, the Canadian NWG concludes the following:

- None of the reactor operators had any advanced warning of impending collapse of the grid.
  - Trend data obtained indicate stable conditions until a few minutes before the event.
  - There were no prior warnings from Ontario's IMO.
- Canadian nuclear power plants did not trigger the power system outage or contribute to its spread. Rather they responded, as anticipated, in order to protect equipment and systems from the grid disturbances. Plant data confirm the following.
  - At Bruce B and Pickering B, frequency and/or voltage fluctuations on the grid resulted in the automatic disconnection of generators from the grid. For those units that were successful in maintaining the unit generators operational, reactor power was automatically reduced.
  - At Darlington, load swing on the grid led to the automatic reduction in power of the four reactors. The generators were, in turn, automatically disconnected from the grid.
  - Three reactors at Bruce B and one at Darlington were returned to 60% power. These ractors were available to deliver power to the grid on the instructions of the IMO.
  - Three units at Darlington were placed in a zero-power hot state, and four units at Pickering B and one unit at Bruce B were placed in a guaranteed shutdown state.
- There were no risks to health and safety of workers or the public as a result of the shutdown of the reactors.
  - Turbine, generator, and reactor automatic safety systems worked as designed to respond to the loss of grid.
  - Station operating staff and management followed approved Operating Policies & Principles (OP&Ps) in responding to the loss of grid. At all times, operators and shift supervisors made appropriately conservative decisions in favor of protecting health and safety.

The Canadian NWG commends the staff of Ontario Power Generation and Bruce Power for their response to the power system outage. At all times, staff acted in accordance with established OP&Ps, and took an appropriately conservative approach to decisions.

During the course of its review, the NWG also identified the following secondary issues:

- Equipment problems and design limitations at Pickering B resulted in a temporary reduction in the effectiveness of some of the multiple safety barriers, although the equipment failure was within the unavailability targets found in the OP&Ps approved by the CNSC as part of Ontario Power Generation's licence.
- Existing OP&Ps place constraints on the use of adjuster rods to respond to events involving rapid reductions in reactor power. While greater flexibility with respect to use of adjuster rods would not have prevented the shutdown, some units, particularly those at Darlington, might have been able to return to service less than 1 hour after the initiating event.
- Off-site power was unavailable for varying periods of time, from approximately 3 hours at Bruce B to approximately 9 hours at Pickering A. Despite the high priority assigned by the IMO to restoring power to the nuclear stations, the stations had some difficulty in obtaining timely information about the status of grid recovery and the restoration of Class IV power. This information is important for Ontario Power Generation's and Bruce Power's response strategy.
- Required regulatory approvals from CNSC staff were obtained quickly and did not delay the restart of the units; however, CNSC staff was unable to immediately activate the CNSC's Emergency Operation Centre because of loss of power to the CNSC's head office building. CNSC staff, therefore, established communications with licensees and the U.S. NRC from other locations.

Introduction

The primary focus of the Canadian NWG during Phase I was to address nuclear power plant response relevant to the power outage of August 14, 2003. Data were collected from each power plant and analyzed in order to determine: the cause of the power outage; whether any activities at these plants caused or contributed to the power outage; and whether there were any significant safety issues. In order to obtain reliable and comparable information and data from each nuclear power plant, a questionnaire was developed to help pinpoint how each nuclear power plant responded to the August 14 grid transients. Where appropriate, additional information was obtained from the ESWG and SWG.

The operating data from each plant were compared against the plant design specifications to determine whether the plants responded as expected. Based on initial plant responses to the questionnaire, supplemental questions were developed, as required, to further clarify outstanding matters. Supplementary information on the design features of Ontario's nuclear power plants was also provided by Ontario Power Generation and Bruce Power. The Canadian NWG also consulted a number of subject area specialists, including CNSC staff, to validate the responses to the questionnaire and to ensure consistency in their interpretation.

Typical Design, Operational, and Protective Features of CANDU Nuclear Power Plants

There are 22 CANDU nuclear power reactors in Canada—20 located in Ontario at 5 multi-unit stations (Pickering A and Pickering B located in Pickering, Darlington located in the Municipality of Clarington, and Bruce A and Bruce B located near Kincardine). There are also single-unit CANDU stations at Bécancour, Québec (Gentilly-2), and Point Lepreau, New Brunswick.

In contrast to the pressurized water reactors used in the United States, which use enriched uranium fuel and a light water coolant-moderator, all housed in a single, large pressure vessel, a CANDU reactor uses fuel fabricated from natural uranium, with heavy water as the coolant and moderator. The fuel and pressurized heavy water coolant are contained in 380 to 480 pressure tubes housed in a calandria containing the heavy water moderator under low pressure. Heat generated by the fuel is removed by heavy water coolant that flows through the pressure tubes and is then circulated to the boilers to produce steam from demineralized water.

While the use of natural uranium fuel offers important benefits from the perspectives of safeguards and operating economics, one drawback is that it restricts the ability of a CANDU reactor to recover from a large power reduction. In particular, the lower reactivity of natural uranium fuel means that CANDU reactors are designed with a small number of control rods (called "adjuster rods") that are only capable of accommodating power reductions to 60%. The consequence of a larger power reduction is that the reactor will "poison out" and cannot be made critical for up to 2 days following a power reduction. By comparison, the use of enriched fuel enables a typical pressurized water reactor to operate with a large number of control rods that can be withdrawn to accommodate power reductions to zero power.

A unique feature of some CANDU plants—namely, Bruce B and Darlington—is a capability to maintain the reactor at 60% full power if the generator becomes disconnected from the grid and to maintain this "readiness" condition if necessary for days. Once reconnected to the grid, the unit can be loaded to 60% full power within several minutes and can achieve full power within 24 hours.

As with other nuclear reactors, CANDU reactors normally operate continuously at full power except when shut down for maintenance and inspections. As such, while they provide a stable source of baseload power generation, they cannot provide significant additional power in response to sudden increases in demand. CANDU power plants are not designed for black-start operation; that is, they are not designed to start up in the absence of power from the grid.

Electrical Distribution Systems

The electrical distribution systems at nuclear power plants are designed to satisfy the high safety and reliability requirements for nuclear systems. This is achieved through flexible bus arrangements, high capacity standby power generation, and ample redundancy in equipment.

Where continuous power is required, power is supplied either from batteries (for continuous DC power, Class I) or via inverters (for continuous AC power, Class II). AC supply for safety-related equipment, which can withstand short interruption (on the order of 5 minutes), is provided by Class III power. Class III power is nominally supplied through Class IV; when Class IV becomes unavailable, standby generators are started automatically, and the safety-related loads are picked up within 5 minutes of the loss of Class IV power.

The Class IV power is an AC supply to reactor equipment and systems that can withstand longer interruptions in power. Class IV power can be supplied either from the generator through a transformer or from the grid by another transformer. Class IV power is not required for reactors to shut down safely.

In addition to the four classes of power described above, there is an additional source of power known as the Emergency Power System (EPS). EPS is a separate power system consisting of its own on-site power generation and AC and DC distribution systems whose normal supply is from the Class III power system. The purpose of the EPS system is to provide power to selected safety-related loads following common mode incidents, such as seismic events.

Protective Features of CANDU Nuclear Power Plants

CANDU reactors typically have two separate, independent and diverse systems to shut down the reactor in the event of an accident or transients in the grid. Shutdown System 1 (SDS1) consists of a large number of cadmium rods that drop into the core to decrease the power level by absorbing neutrons. Shutdown System 2 (SDS2) consists of high-pressure injection of gadolinium nitrate into the low-pressure moderator to decrease the power level by absorbing neutrons. Although Pickering A does not have a fully independent SDS2, it does have a second shutdown mechanism, namely, the fast drain of the moderator out of the calandria; removal of the moderator significantly reduces the rate of nuclear fission, which reduces reactor power. Also, additional trip circuits and shutoff rods have recently been added to Pickering A Unit 4 (Shutdown System Enhancement, or SDS-E). Both SDS1 and SDS2 are capable of reducing reactor power from 100% to about 2% within a few seconds of trip initiation.

Fuel Heat Removal Features of CANDU Nuclear Power Plants

Following the loss of Class IV power and shutdown of the reactor through action of SDS1 and/or SDS2, significant heat will continue to be generated in the reactor fuel from the decay of fission products. The CANDU design philosophy is to provide defense in depth in the heat removal systems.

Immediately following the trip and prior to restoration of Class III power, heat will be removed from the reactor core by natural circulation of coolant through the Heat Transport System main circuit following rundown of the main Heat Transport pumps (first by thermosyphoning and later by intermittent buoyancy induced flow). Heat will be rejected from the secondary side of the steam generators through the atmospheric steam discharge valves. This mode of operation can be sustained for many days with additional feedwater supplied to the steam generators via the Class III powered auxiliary steam generator feed pump(s).

In the event that the auxiliary feedwater system becomes unavailable, there are two alternate EPS powered water supplies to steam generators, namely, the Steam Generator Emergency Coolant System and the Emergency Service Water System. Finally, a separate and independent means of cooling the fuel is by forced circulation by means of the Class III powered shutdown cooling system; heat removal to the shutdown cooling heat exchangers is by means of the Class III powered components of the Service Water System.

CANDU Reactor Response to Loss-of-Grid Event

Response to Loss of Grid

In the event of disconnection from the grid, power to safely shut down the reactor and maintain essential systems will be supplied from batteries and standby generators. The specific response of a reactor to disconnection from the grid will depend on the reactor design and the condition of the unit at the time of the event.

60% Reactor Power: All CANDU reactors are designed to operate at 60% of full power following the loss of off-site power. They can operate at this level as long as demineralized water is available for the boilers. At Darlington and Bruce B, steam can be diverted to the condensers and recirculated to the boilers. At Pickering A and Pickering B, excess steam is vented to the atmosphere, thereby limiting the operating time to the available inventory of demineralized water.

0% Reactor Power, Hot: The successful transition from 100% to 60% power depends on several systems responding properly, and continued operation is not guaranteed. The reactor may shut down automatically through the operation of the process control systems or through the action of either of the shutdown systems.

Should a reactor shutdown occur following a load rejection, both Class IV power supplies (from the generator and the grid) to that unit will become unavailable. The main Heat Transport pumps will trip, leading to a loss of forced circulation of coolant through the core. Decay heat will be continuously removed through natural circulation (thermosyphoning) to the boilers, and steam produced in the boilers will be exhausted to the atmosphere via atmospheric steam discharge valves. The Heat Transport System will be maintained at around 250 to 265 degrees Celsius during thermosyphoning. Standby generators will start automatically and restore Class III power to key safety-related systems. Forced circulation in the Heat Transport System will be restored once either Class III or Class IV power is available.

When shut down, the natural decay of fission products will lead to the temporary buildup of neutron absorbing elements in the fuel. If the reactor is not quickly restarted to reverse this natural process, it will "poison-out." Once poisoned-out, the reactor cannot return to operation until the fission products have further decayed, a process which typically takes up to 2 days.

Overpoisoned Guaranteed Shutdown State: In the event that certain problems are identified when reviewing the state of the reactor after a significant transient, the operating staff will cool down and depressurize the reactor, then place it in an overpoisoned guaranteed shutdown state (GSS) through the dissolution of gadolinium nitrate into the moderator. Maintenance will then be initiated to correct the problem.

Return to Service Following Loss of Grid

The return to service of a unit following any one of the above responses to a loss-of-grid event is discussed below. It is important to note that the descriptions provided relate to operations on a single unit. At multi-unit stations, the return to service of several units cannot always proceed in parallel, due to constraints on labor availability and the need to focus on critical evolutions, such as taking the reactor from a subcritical to a critical state.

60% Reactor Power: In this state, the unit can be resynchronized consistent with system demand, and power can be increased gradually to full power over approximately 24 hours.

0% Reactor Power, Hot: In this state, after approximately 2 days for the poison-out, the turbine can be run up and the unit synchronized. The reactor may shut down automatically through the operation of the process control systems or through the action of either of the shutdown systems. Thereafter, power can be increased to high power over the next day. This restart timeline does not include the time required for any repairs or maintenance that might have been necessary during the outage.

Overpoisoned Guaranteed Shutdown State: Placing the reactor in a GSS after it has been shut down requires approximately 2 days. Once the condition that required entry to the GSS is rectified, the restart requires removal of the guarantee, removal of the gadolinium nitrate through ion exchange process, heatup of the Heat Transport System, and finally synchronization to the grid. Approximately 4 days are required to complete these restart activities. In total, 6 days from shutdown are required to return a unit to service from the GSS, and this excludes any repairs that might have been required while in the GSS.

Summary of Canadian Nuclear Power Plant Response to and Safety During the August 14 Outage

On the afternoon of August 14, 2003, 15 Canadian nuclear units were operating: 13 in Ontario, 1 in Québec, and 1 in New Brunswick. Of the 13 Ontario reactors that were critical at the time of the event, 11 were operating at or near full power and 2 at low power (Pickering B Unit 7 and Pickering A Unit 4). All 13 of the Ontario reactors disconnected from the grid as a result of the grid disturbance. Seven of the 11 reactors operating at high power shut down, while the remaining 4 operated in a planned manner that enabled them to remain available to reconnect to the grid at the request of Ontario's IMO. Of the 2 Ontario reactors operating at low power, Pickering A Unit 4 tripped automatically, and Pickering B Unit 7 was tripped manually and shut down. In addition, a transient was experienced at New Brunswick Power's Point Lepreau Nuclear Generating Station, resulting in a reduction in power. Hydro Québec's Gentilly-2 nuclear station continued to operate normally as the Hydro Québec grid was not affected by the grid disturbance.

Nuclear Power Plants With Significant Transients

Pickering Nuclear Generating Station. The Pickering Nuclear Generating Station (PNGS) is located in Pickering, Ontario, on the shores of Lake Ontario, 30 kilometers east of Toronto. It houses 8 nuclear reactors, each capable of delivering 515 MW to the grid. Three of the 4 units at Pickering A (Units 1 through 3) have been shut down since late 1997. Unit 4 was restarted earlier this year following a major refurbishment and was in the process of being commissioned at the time of the event. At Pickering B, 3 units were operating at or near 100% prior to the event, and Unit 7 was being started up following a planned maintenance outage.

Pickering A. As part of the commissioning process, Unit 4 at Pickering A was operating at 12% power in preparation for synchronization to the grid. The reactor automatically tripped on SDS1 due to Heat Transport Low Coolant Flow, when the Heat Transport main circulating pumps ran down following the Class IV power loss. The decision was then made to return Unit 4 to the guaranteed shutdown state. Unit 4 was synchronized to the grid on August 20, 2003. Units 1, 2 and 3 were in lay-up mode.

Pickering B. The Unit 5 Generator Excitation System transferred to manual control due to large voltage oscillations on the grid at 16:10 EDT and then tripped on Loss of Excitation about 1 second later (prior to grid frequency collapse). In response to the generator trip, Class IV buses transferred to the system transformer and the reactor setback. The grid frequency collapse caused the System Service Transformer to disconnect from the grid, resulting in a total loss of Class IV power. The reactor consequently tripped on the SDS1 Low Gross Flow parameter followed by an SDS2 trip due to Low Core Differential Pressure.

The Unit 6 Generator Excitation System also transferred to manual control at 16:10 EDT due to large voltage oscillations on the grid and the generator remained connected to the grid in manual voltage control. Approximately 65 seconds into the event, the grid under-frequency caused all the Class IV buses to transfer to the Generator Service Transformer. Ten seconds later, the generator separated from the Grid. Five seconds later, the generator tripped on Loss of Excitation, which caused a total loss of Class IV power. The reactor consequently tripped on the SDS1 Low Gross Flow parameter, followed by an SDS2 trip due to Low Core Differential Pressure.

Unit 7 was coming back from a planned maintenance outage and was at 0.9% power at the time of the event. The unit was manually tripped after loss of Class IV power, in accordance with procedures and returned to guaranteed shutdown state.

Unit 8 reactor automatically set back on load rejection. The setback would normally have been terminated at 20% power but continued to 2% power because of the low boiler levels. The unit subsequently tripped on the SDS1 Low Boiler Feedline Pressure parameter due to a power mismatch between the reactor and the turbine.

The following equipment problems were noted. At Pickering, the High Pressure Emergency Coolant Injection System (HPECIS) pumps are designed to operate from a Class IV power supply. As a result of the shutdown of all the operating units, the HPECIS at both Pickering A and Pickering B became unavailable for 5.5 hours. (The operating licenses for Pickering A and Pickering B permit the HPECIS to be unavailable for up to 8 hours annually. This was the first unavailability of the year.) In addition, Emergency High Pressure Service Water System restoration for all Pickering B units was delayed because of low suction pressure supplying the Emergency High Pressure Service Water pumps. Manual operator intervention was required to restore some pumps back to service.

Units were synchronized to the grid as follows: Unit 8 on August 22, Unit 5 on August 23, Unit 6 on August 25, and Unit 7 on August 29.

Darlington Nuclear Generating Station. Four reactors are located at the Darlington Nuclear Generation Station, which is on the shores of Lake Ontario in the Municipality of Clarington, 70 kilometers east of Toronto. All four of the reactors are licensed to operate at 100% of full power, and each is capable of delivering approximately 880 MW to the grid.

Unit 1 automatically stepped back to the 60% reactor power state upon load rejection at 16:12 EDT. Approval by the shift supervisor to automatically withdraw the adjuster rods could not be provided due to the brief period of time for the shift supervisor to complete the verification of systems as per procedure. The decreasing steam pressure and turbine frequency then required the reactor to be manually tripped on SDS1, as per procedure for loss of Class IV power. The trip occurred at 16:24 EDT, followed by a manual turbine trip due to under-frequency concerns.

Like Unit 1, Unit 2 automatically stepped back upon load rejection at 16:12 EDT. As with Unit 1, there was insufficient time for the shift supervisor to complete the verification of systems, and faced with decreasing steam pressure and turbine frequency, the decision was made to shut down Unit 2. Due to under-frequency on the main Primary Heat Transport pumps, the turbine was tripped manually which resulted in an SDS1 trip at 16:28 EDT.

Unit 3 experienced a load rejection at 16:12 EDT, and during the stepback Unit 3 was able to sustain operation with steam directed to the condensers.

After system verifications were complete, approval to place the adjuster rods on automatic was obtained in time to recover, at 59% reactor power.

The unit was available to resynchronize to the grid. Unit 4 experienced a load rejection at 16:12 EDT, and required a manual SDS1 trip due to the loss of Class II bus. This was followed by a manual turbine trip.

The following equipment problems were noted: Unit 4 Class II inverter trip on BUS A3 and subsequent loss of critical loads prevented unit recovery. The Unit 0 Emergency Power System BUS B135 power was lost until the Class III power was restored. (A planned battery bank B135 change out was in progress at the time of the blackout.)

Units were synchronized to the grid as follows: Unit 3 at 22:00 EDT on August 14; Unit 2 on August 17, 2003; Unit 1 on August 18, 2003; and Unit 4 on August 18, 2003.

Bruce Power. Eight reactors are located at Bruce Power on the eastern shore of Lake Huron between Kincardine and Port Elgin, Ontario. Units 5 through 8 are capable of generating 840 MW each. Presently these reactors are operating at 90% of full power due to license conditions imposed by the CNSC. Units 1 through 4 have been shutdown since December 31, 1997. Units 3 and 4 are in the process of startup.

Bruce A. Although these reactors were in guaranteed shutdown state, they were manually tripped, in accordance with operating procedures. SDS1 was manually tripped on Units 3 and 4, as per procedures for a loss of Class IV power event. SDS1 was re-poised on both units when the station power supplies were stabilized. The emergency transfer system functioned as per design, with the Class III standby generators picking up station electrical loads. The recently installed Qualified Diesel Generators received a start signal and were available to pick up emergency loads if necessary.

Bruce B. Units 5, 6, 7, and 8 experienced initial generation rejection and accompanying stepback on all four reactor units. All generators separated from the grid on under-frequency at 16:12 EDT. Units 5, 7, and 8 maintained reactor power at 60% of full power and were immediately available for reconnection to the grid.

Although initially surviving the loss of grid event, Unit 6 experienced an SDS1 trip on insufficient Neutron Over Power (NOP) margin. This occurred while withdrawing Bank 3 of the adjusters in an attempt to offset the xenon transient, resulting in a loss of Class IV power.

The following equipment problems were noted: An adjuster rod on Unit 6 had been identified on August 13, 2003, as not working correctly. Unit 6 experienced a High Pressure Recirculation Water line leak, and the Closed Loop Demineralized Water loop lost inventory to the Emergency Water Supply System.

Units were synchronized to the grid as follows: Unit 8 at 19:14 EDT on August 14, 2003; Unit 5 at 21:04 EDT on August 14; and Unit 7 at 21:14 EDT on August 14, 2003. Unit 6 was resynchronized at 02:03 EDT on August 23, 2003, after maintenance was conducted.

Point Lepreau Nuclear Generating Station. The Point Lepreau nuclear station overlooks the Bay of Fundy on the Lepreau Peninsula, 40 kilometers southwest of Saint John, New Brunswick. Point Lepreau is a single-unit CANDU 6, designed for a gross output of 680 MW. It is owned and operated by New Brunswick Power.

Point Lepreau was operating at 91.5% of full power (610 MWe) at the time of the event. When the event occurred, the unit responded to changes in grid frequency as per design. The net impact was a short-term drop in output by 140 MW, with reactor power remaining constant and excess thermal energy being discharged via the unit steam discharge valves. During the 25 seconds of the event, the unit stabilizer operated numerous times to help dampen the turbine generator speed oscillations that were being introduced by the grid frequency changes. Within 25 minutes of the event initiation, the turbine generator was reloaded to 610 MW. Given the nature of the event that occurred, there were no unexpected observations on the New Brunswick Power grid or at Point Lepreau Generating Station throughout the ensuing transient.

Nuclear Power Plants With No Transient

Gentilly-2 Nuclear Station. Hydro Québec owns and operates Gentilly-2 nuclear station, located on the south shore of the St. Lawrence River opposite the city of Trois-Rivières, Québec. Gentilly-2 is capable of delivering approximately 675 MW to Hydro Québec's grid. The Hydro Québec grid was not affected by the power system outage and Gentilly-2 continued to operate normally.

General Observations Based on the Facts Found During Phase One

Following the review of the data provided by the Canadian nuclear power plants, the Nuclear Working Group concludes the following:

- None of the reactor operators had any advanced warning of impending collapse of the grid.
- Canadian nuclear power plants did not trigger the power system outage or contribute to its spread.
- There were no risks to the health and safety of workers or the public as a result of the concurrent shutdown of several reactors. Automatic safety systems for the turbine generators and reactors worked as designed. (See Table 7.2 for a summary of shutdown events for Canadian nuclear power plants.)

The NWG also identified the following secondary issues:

- Equipment problems and design limitations at Pickering B resulted in a temporary reduction in the effectiveness of some of the multiple safety barriers, although the equipment failure was within the unavailability targets found in the OP&Ps approved by the CNSC as part of Ontario Power Generation's license.
- Existing OP&Ps place constraints on the use of adjuster rods to respond to events involving rapid reductions in reactor power. While greater flexibility with respect to use of adjuster rods would not have prevented the shutdown, some units, particularly those at Darlington, might have been able to return to service less than 1 hour after the initiating event.
- Off-site power was unavailable for varying periods of time, from approximately 3 hours at Bruce B to approximately 9 hours at Pickering A. Despite the high priority assigned by the IMO to restoring power to the nuclear stations, the stations had some difficulty obtaining timely information about the status of grid recovery and the restoration of Class IV power. This information is important for Ontario Power Generation's and Bruce Power's response strategy.
- Required regulatory approvals from CNSC staff were obtained quickly and did not delay the restart of the units; however, CNSC staff was unable to immediately activate the CNSC's Emergency Operation Centre because of loss of power to the CNSC's head office building. CNSC staff, therefore, established communications with licensees and the U.S. NRC from other locations.

Table 7.2. Summary of Shutdown Events for Canadian Nuclear Power Plants

Generating Station	Unit	Operating Status at Time of Event			Response to Event		Reactor Trip	
		Full Power	Startup	Not Operating	Stepback to 60% Power, Available To Supply Grid	Turbine Trip	SDS1	SDS2
Pickering NGS	1			√			(a)	
	2			√				
	3			√				
	4		√				√	(b)
	5	√					√	√
	6	√					√	√
	7		√				√	
	8	√					√	
Darlington NGS	1	√				√	√	
	2	√				√	√	
	3	√			√			
	4	√				√	√	
Bruce Nuclear Power Development	1			√				
	2			√				
	3			√			√	
	4			√			√	
	5	√			√			
	6	√					√	
	7	√			√			
	8	√			√			

[a]Pickering A Unit 1 tripped as a result of electrical bus configuration immediately prior to the event which resulted in a temporary loss of Class II power.
[b]Pickering A Unit 4 also tripped on SDS-E.
Notes: Unit 7 at Pickering B was operating at low power, warming up prior to reconnecting to the grid after a maintenance outage. Unit 4 at Pickering A was producing at low power, as part of the reactor's commissioning after extensive refurbishment since being shut down in 1997.

8. Physical and Cyber Security Aspects of the Blackout

Summary

The objective of the Security Working Group (SWG) is to determine what role, if any, that a malicious cyber event may have played in causing, or contributing to, the power outage of August 14, 2003. Analysis to date provides no evidence that malicious actors are responsible for, or contributed to, the outage. The SWG acknowledges reports of al-Qaeda claims of responsibility for the power outage of August 14, 2003; however, those claims are not consistent with the SWG's findings to date. There is also no evidence, nor is there any information suggesting, that viruses and worms prevalent across the Internet at the time of the outage had any significant impact on power generation and delivery systems. SWG analysis to date has brought to light certain concerns with respect to: the possible failure of alarm software; links to control and data acquisition software; and the lack of a system or process for some operators to view adequately the status of electric systems outside their immediate control.

Further data collection and analysis will be undertaken by the SWG to test the findings detailed in this interim report and to examine more fully the cyber security aspects of the power outage. The outcome of Electric System Working Group (ESWG) root cause analysis will serve to focus this work. As the significant cyber events are identified by the ESWG, the SWG will examine them from a security perspective.

Security Working Group: Mandate and Scope

It is widely recognized that the increased reliance on information technology (IT) by critical infrastructure sectors, including the energy sector, has increased their vulnerability to disruption via cyber means. The ability to exploit these vulnerabilities has been demonstrated in North America. The SWG was established to address the cyber-related aspects of the August 14, 2003, power outage. The SWG is made up of U.S. and Canadian Federal, State, Provincial, and local experts in both physical and cyber security. For the purposes of its work, the SWG has defined a "malicious cyber event" as the manipulation of data, software or hardware for the purpose of deliberately disrupting the systems that control and support the generation and delivery of electric power.

The SWG is working closely with the U.S. and Canadian law enforcement, intelligence, and homeland security communities to examine the possible role of malicious actors in the power outage of August 14, 2003. A primary activity to date has been the collection and review of available intelligence that may relate to the outage.

The SWG is also collaborating with the energy industry to examine the cyber systems that control power generation and delivery operations, the physical security of cyber assets, cyber policies and procedures, and the functionality of supporting infrastructures-such as communication systems and backup power generation, which facilitate the smooth-running operation of cyber assets-to determine whether the operation of these systems was affected by malicious activity. The collection of information along these avenues of inquiry is ongoing.

The SWG is coordinating its efforts with those of the other Working Groups, and there is a significant interdependence on the work products and findings of each group. The SWG's initial focus is on the cyber operations of those companies in the United States involved in the early stages of the power outage timeline, as identified by the ESWG. The outcome of ESWG analysis will serve to identify key events that may have caused, or contributed to, the outage. As the significant cyber events are identified, the SWG will examine them from a security perspective. The amount of information for analysis is identified by the ESWG as pertinent to the SWG's analysis is considerable.

Examination of the physical, non-cyber infrastructure aspects of the power outage of August 14, 2003, is outside the scope of the SWG's analysis.

Nevertheless, if a breach of physical security unrelated to the cyber dimensions of the infrastructure comes to the SWG's attention during the course of the work of the Task Force, the SWG will conduct the necessary analysis.

Also outside the scope of the SWG's work is analysis of the cascading impacts of the power outage on other critical infrastructure sectors. Both the Canadian Office of Critical Infrastructure Protection and Emergency Preparedness (OCIPEP) and the U.S. Department of Homeland Security (DHS) are examining these issues, but not within the context of the Task Force. The SWG is closely coordinating its efforts with OCIPEP and DHS.

Cyber Security in the Electricity Sector

The generation and delivery of electricity has been, and continues to be, a target of malicious groups and individuals intent on disrupting the electric power system. Even attacks that do not directly target the electricity sector can have disruptive effects on electricity system operations. Many malicious code attacks, by their very nature, are unbiased and tend to interfere with operations supported by vulnerable applications. One such incident occurred in January 2003, when the "Slammer" Internet worm took down monitoring computers at FirstEnergy Corporation's idled Davis-Besse nuclear plant. A subsequent report by the North American Electric Reliability Council (NERC) concluded that, although it caused no outages, the infection blocked commands that operated other power utilities. The report, "NRC Issues Information Notice on Potential of Nuclear Power Plant Network to Worm Infection," is available at web site http://www.nrc.gov/reading-rm/doc-collections/news/2003/03-108.html.

This example, among others, highlights the increased vulnerability to disruption via cyber means faced by North America's critical infrastructure sectors, including the energy sector. Of specific concern to the U.S. and Canadian governments are the Supervisory Control and Data Acquisition (SCADA) systems, which contain computers and applications that perform a wide variety of functions across many industries. In electric power, SCADA includes telemetry for status and control, as well as Energy Management Systems (EMS), protective relaying, and automatic generation control. SCADA systems were developed to maximize functionality and interoperability, with little attention given to cyber security. These systems, many of which were intended to be isolated, are now, for a variety of business and operational reasons, either directly or indirectly connected to the global Internet. For example, in some instances, there may be a need for employees to monitor SCADA systems remotely. However, connecting SCADA systems to a remotely accessible computer network can present security risks. These risks include the compromise of sensitive operating information and the threat of unauthorized access to SCADA systems' control mechanisms.

Security has always been a priority for the electricity sector in North America; however, it is a greater priority now than ever before. Electric system operators recognize that the threat environment is changing and that the risks are greater than in the past, and they have taken steps to improve their security postures. NERC's Critical Infrastructure Protection Advisory Group has been examining ways to improve both the physical and cyber security dimensions of the North American power grid. This group includes Canadian and U.S. industry experts in the areas of cyber security, physical security and operational security. The creation of a national SCADA program to improve the physical and cyber security of these control systems is now also under discussion in the United States. The Canadian Electrical Association Critical Infrastructure Working Group is examining similar measures.

Information Collection and Analysis

In addition to analyzing information already obtained from stakeholder interviews, telephone transcripts, law enforcement and intelligence information, and other ESWG working documents, the SWG will seek to review and analyze other sources of data on the cyber operations of those companies in the United States involved in the early stages of the power outage timeline, as identified by the ESWG. Available information includes log data from routers, intrusion detection systems, firewalls, and EMS; change management logs; and physical security materials. Data are currently being collected, in collaboration with the private sector and with consideration toward its protection from further disclosure where there are proprietary or national security concerns.

The SWG is divided into six sub-teams to address the discrete components of this investigation: Cyber Analysis, Intelligence Analysis, Physical Analysis, Policies and Procedures, Supporting Infrastructure, and Root Cause Liaison. The SWG organized itself in this manner to create a holistic approach to each of the main areas of concern with regard to power grid vulnerabilities. Rather than analyze each area of concern separately, the SWG sub-team structure provides a more comprehensive framework in which to investigate whether malicious activity was a cause of the power outage of August 14, 2003. Each sub-team is staffed with Subject Matter Experts (SMEs) from government, industry, and academia to provide the analytical breadth and depth necessary to complete its objective. A detailed overview of the sub-team structure and activities, those planned and those taken, for each sub-team is provided below.

Cyber Analysis

The Cyber Analysis sub-team is led by the CERT® Coordination Center (CERT/CC) at Carnegie Mellon University and the Royal Canadian Mounted Police (RCMP). This team is focused on analyzing and reviewing the electronic media of computer networks in which online communications take place. The sub-team is examining these networks to determine whether they were maliciously used to cause, or contribute to, the August 14 outage. It is specifically reviewing the existing cyber topology, cyber logs, and EMS logs. The team is also conducting interviews with vendors to identify known system flaws and vulnerabilities. The sub-team is collecting, processing, and synthesizing data to determine whether a malicious cyber-related attack was a direct or indirect cause of the outage.

This sub-team has taken a number of steps in recent weeks, including reviewing NERC reliability standards to gain a better understanding of the overall security posture of the electric power industry. Additionally, the sub-team participated in meetings in Baltimore on August 22 and 23, 2003. The meetings provided an opportunity for the cyber experts and the power industry experts to understand the details necessary to conduct an investigation. The cyber data retention request was produced during this meeting.

Members of the sub-team also participated in the NERC/Department of Energy (DOE) Fact Finding meeting held in Newark, New Jersey, on September 8, 2003. Each company involved in the outage provided answers to a set of questions related to the outage. The meeting helped to provide a better understanding of what each company experienced before, during, and after the outage. Additionally, sub-team members participated in interviews with the control room operators from FirstEnergy on October 8 and 9, 2003, and from Cinergy on October 10, 2003. These interviews have identified several key areas for further discussion.

The Cyber Analysis sub-team continues to gain a better understanding of events on August 14, 2003. Future analysis will be driven by information received from the ESWG's Root Cause Analysis sub-team and will focus on:

- Conducting additional interviews with control room operators and IT staff from the key companies involved in the outage.
- Conducting interviews with the operators and IT staff responsible for the NERC Interchange Distribution Calculator system. Some reports indicate that this system may have been unavailable during the time of the outage.
- Conducting interviews with key vendors for the EMS.
- Analyzing the configurations of routers, firewalls, intrusion detection systems, and other network devices to get a better understanding of potential weaknesses in the control system cyber defenses.
- Analyzing logs and other information for signs of unauthorized activity.

Intelligence Analysis

The Intelligence Analysis sub-team is led by DHS and the RCMP, which are working closely with Federal, State, and local law enforcement, intelligence, and homeland security organizations to assess whether the power outage was the result of a malicious attack. Preliminary analysis provides no evidence that malicious actors-either individuals or organizations-are responsible for, or contributed to, the power outage of August 14, 2003. Additionally, the sub-team has found no indication of deliberate physical damage to power generating stations and delivery lines on the day of the outage, and there are no reports indicating that the power outage was caused by a computer network attack.

Both U.S. and Canadian government authorities provide threat intelligence information to their respective energy sectors when appropriate. No intelligence reports before, during, or after the power outage indicated any specific terrorist plans or operations against the energy infrastructure. There was, however, threat information of a general nature relating to the sector, which was provided to the North American energy industry by U.S. and Canadian government agencies in late July 2003. This information indicated that al-Qaeda might attempt to carry out a physical attack involving explosions at oil production facilities, power plants, or nuclear plants on the U.S. East Coast during the summer of 2003. The type of physical attack described in the intelligence that prompted this threat warning is not consistent with the events of the power outage; there is no indication of a kinetic event before, during, or immediately after the August 14 outage.

Despite all the above indications that no terrorist activity caused the power outage, al-Qaeda did publicly claim responsibility for its occurrence:

- **August 18, 2003:** Al-Hayat, an Egyptian media outlet, published excerpts from a communiqué attributed to al-Qaeda. Al Hayat claimed to have obtained the communiqué from the website of the International Islamic Media Center. The content of the communiqué asserts that the "brigades of Abu Fahes Al Masri had hit two main power plants supplying the East of the U.S., as well as major industrial cities in the U.S. and Canada, 'its ally in the war against Islam (New York and Toronto) and their neighbors.'" Furthermore, the operation "was carried out on the orders of Osama bin Laden to hit the pillars of the U.S. economy," as "a realization of bin Laden's promise to offer the Iraqi people a present." The communiqué does not specify the way in which the alleged sabotage was carried out, but it does elaborate on the alleged damage to the U.S. economy in the areas of finance, transportation, energy, and telecommunications.

Additional claims and commentary regarding the power outage appeared in various Middle Eastern media outlets:

- **August 26, 2003:** A conservative Iranian daily newspaper published a commentary regarding the potential of computer technology as a tool for terrorists against infrastructures dependent on computer networks-most notably, water, electric, public transportation, trade organizations, and "supranational companies" in the United States.
- **September 4, 2003:** An Islamist participant in a Jihadist chat room forum claimed that sleeper cells associated with al-Qaeda used the power outage as a cover to infiltrate the United States from Canada.

These claims above, as known, are not consistent with the SWG's findings to date. They are also not consistent with recent congressional testimony by the U.S. Federal Bureau of Investigation (FBI). Larry A. Mefford, Executive Assistant Director in charge of the FBI's Counterterrorism and Counterintelligence programs, testified to the U.S. Congress on September 4, 2003, that, "To date, we have not discovered any evidence indicating that the outage was a result of activity by international or domestic terrorists or other criminal activity." He also testified that, "The FBI has received no specific, credible threats to electronic power grids in the United States in the recent past and the claim of the Abu Hafs al-Masri Brigade to have caused the blackout appears to be no more than wishful thinking. We have no information confirming the actual existence of this group." Mr. Mefford's Statement for the Record is available at web site http://www.fbi.gov/congress/congress03/mefford090403.htm.

Current assessments suggest that there are terrorists and other malicious actors who have the capability to conduct a malicious cyber attack with potential to disrupt the energy infrastructure. Although such an attack cannot be ruled out entirely, an examination of available information and intelligence does not support any claims of a deliberate attack against the energy infrastructure on, or leading up to, August 14, 2003. The few instances of physical damage that occurred on power delivery lines were the result of natural acts and not of sabotage. No intelligence reports before, during, or after the power outage indicate any specific terrorist plans or operations against the energy infrastructure. No incident reports detail suspicious activity near the power generation plants or delivery lines in question.

Physical Analysis

The Physical Analysis sub-team is led by the U.S. Secret Service and the RCMP. These organizations have particular expertise in physical security assessments in the energy sector. The sub-team is focusing on issues related to how the cyber-related facilities of the energy sector companies are secured, including the physical integrity of data centers and control rooms, along with security procedures and policies used to limit access to sensitive areas. Focusing on the facilities identified as having a causal relationship to the outage, the sub-team is seeking to determine whether the physical integrity of the cyber facilities was breached, either externally or by an insider, before or during the outage; and if so, whether such a breach caused or contributed to the power outage. Although the sub-team has analyzed information provided to both the EWG and the Nuclear Working Group (NWG), the Physical Analysis sub-team is also reviewing information resulting from recent face-to-face meetings with energy sector personnel and site visits to energy sector facilities, to determine the physical integrity of the cyber infrastructure.

The sub-team has compiled a list of questions covering location, accessibility, cameras, alarms, locks, and fire protection and water systems as they apply to computer server rooms. Based on discussions of these questions during its interviews, the sub-team is in the process of ascertaining whether the physical integrity of the cyber infrastructure was breached. Additionally, the sub-team is examining access and control measures used to allow entry into command and control facilities and the integrity of remote facilities.

The sub-team is also concentrating on mechanisms used by the companies to report unusual incidents within server rooms, command and control rooms, and remote facilities. The sub-team is also addressing the possibility of an insider attack on the cyber infrastructure.

Policies and Procedures

The Policies and Procedures sub-team is led by DHS and OCIPEP, which have personnel with strong backgrounds in the fields of electric delivery operations, automated control systems (including SCADA and EMS), and information security. The sub-team is focused on examining the overall policies and procedures that may or may not have been in place during the events leading up to and during the August 14 power outage. The team is examining policies that are centrally related to the cyber systems of the companies identified in the early stages of the power outage. Of specific interest are policies and procedures regarding the upgrade and maintenance (to include system patching) of the command and control (C2) systems, including SCADA and EMS. Also of interest are the procedures for contingency operations and restoration of systems in the event of a computer system failure or a cyber event, such as an active hack or the discovery of malicious code. The group is conducting further interviews and is continuing its analysis to build solid conclusions about the policies and procedures relating to the outage.

Supporting Infrastructure

The Supporting Infrastructure sub-team is led by a DHS expert with experience assessing supporting infrastructure elements such as water cooling for computer systems, backup power systems, heating, ventilation and air conditioning (HVAC), and supporting telecommunications networks. OCIPEP is the Canadian co-lead for this effort. The sub-team is analyzing the integrity of the supporting infrastructure and its role, if any, in the August 14 power outage, and whether the supporting infrastructure was performing at a satisfactory level before and during the outage. In addition, the team is contacting vendors to determine whether there were maintenance issues that may have affected operations during or before the outage.

The sub-team is focusing specifically on the following key issues in visits to each of the designated electrical entities:

- Carrier/provider/vendor for the supporting infrastructure services and/or systems at select company facilities
- Loss of service before and/or after the power outage
- Conduct of maintenance activities before and/or after the power outage
- Conduct of installation activities before and/or after the power outage
- Conduct of testing activities before and/or after the power outage
- Conduct of exercises before and/or after the power outage
- Existence of a monitoring process (log, checklist, etc.) to document the status of supporting infrastructure services.

Root Cause Analysis

The SWG Root Cause Liaison sub-team (SWG/RC) has been following the work of the ESWG to identify potential root causes of the power outage. As these root cause elements are identified, the sub-team will assess with the ESWG any potential linkages to physical and/or cyber malfeasance.

The root cause analysis work of the ESWG is still in progress; however, the initial analysis has found no causal link between the power outage and malicious activity, whether physical or cyber initiated. Root cause analysis for an event like the August 14 power outage involves a detailed process to develop a hierarchy of actions and events that suggest causal factors. The process includes: development of a detailed timeline of the events, examination of actions related to the events, and an assessment of factors that initiated or exacerbated the events. An assessment of the impact of physical security as a contributor to the power outage is conditional upon discovery of information suggesting that a malicious physical act initiated or exacerbated the power outage. There are no such indications thus far, and no further assessment by the SWG in this area is indicated.

Cyber Timeline

The following sequence of events was derived from discussions with representatives of FirstEnergy and the Midwest Independent Transmission System Operator (MISO). All times are approximate and will need to be confirmed by an analysis of company log data.

- The first significant cyber-related event of August 14, 2003, occurred at 12:40 EDT at the MISO. At this time, a MISO EMS engineer purposely disabled the automatic periodic trigger on the State Estimator (SE) application, which allows MISO to determine the real-time state of the power system for its region. Disabling of the automatic periodic trigger, a program feature that causes the SE to run automatically every 5 minutes, is a necessary operating procedure when resolving a mismatched solution produced by the SE. The EMS engineer determined that the mismatch in the SE solution was due to the SE model depicting Cinergy's Bloomington-Denois Creek 230-kV line as being in service, when it had actually been out of service since 12:12 EDT.
- At 13:00 EDT, after making the appropriate changes to the SE model and manually triggering the SE, the MISO EMS engineer achieved two valid solutions.
- At 13:30 EDT, the MISO EMS engineer went to lunch. He forgot to re-engage the automatic periodic trigger.
- At 14:14 EDT, FirstEnergy's "Alarm and Event Processing Routine" (AEPR)-a key software program that gives operators visual and audible indications of events occurring on their portion of the grid-began to malfunction. FirstEnergy system operators were unaware that the software was not functioning properly. This software did not become functional again until much later that evening.
- At 14:40 EDT, an Ops engineer discovered that the SE was not solving. He went to notify an EMS engineer.
- At 14:41 EDT, FirstEnergy's server running the AEPR software failed to the backup server. Control room staff remained unaware that the AEPR software was not functioning properly.
- At 14:44 EDT, an MISO EMS engineer, after being alerted by the Ops engineer, reactivated the automatic periodic trigger and, for speed, manually triggered the program. The SE program again showed a mismatch.
- At 14:54 EDT, FirstEnergy's backup server failed. AEPR continued to malfunction. The Area Control Error (ACE) calculations and Strip Charting routines malfunctioned, and the dispatcher user interface slowed significantly.
- At 15:00 EDT, FirstEnergy used its emergency backup system to control the system and make ACE calculations. ACE calculations and control systems continued to run on the emergency backup system until roughly 15:08 EDT, when the primary server was restored.
- At 15:05 EDT, FirstEnergy's Harding-Chamberlin 345-kV line tripped and locked out. FE system operators did not receive notification from the AEPR software, which continued to malfunction, unbeknownst to the FE system operators.
- At 15:08 EDT, using data obtained at roughly 15:04 EDT (it takes about 5 minutes for the SE to provide a result), the MISO EMS engineer concluded that the SE mismatched due to a line outage. His experience allowed him to isolate the outage to the Stuart-Atlanta 345-kV line (which tripped about an hour earlier, at 14:02 EDT). He took the Stuart-Atlanta line out of service in the SE model and got a valid solution.
- Also at 15:08 EDT, the FirstEnergy primary server was restored. ACE calculations and control systems were now running on the primary server. AEPR continued to malfunction, unbeknownst to the FirstEnergy system operators.
- At 15:09 EDT, the MISO EMS engineer went to the control room to tell the operators that he thought the Stuart-Atlanta line was out of service. Control room operators referred to their

"Outage Scheduler" and informed the EMS engineer that their data showed the Stuart-Atlanta line was "up" and that the EMS engineer should depict the line as in service in the SE model. At 15:17 EDT, the EMS engineer ran the SE with the Stuart-Atlanta line "live." The model again mismatched.

- At 15:29 EDT, the MISO EMS Engineer asked MISO operators to call the PJM Interconnect to determine the status of the Stuart-Atlanta line. MISO was informed that the Stuart-Atlanta line had tripped at 14:02 EDT. The EMS engineer adjusted the model, which by that time had been updated with the 15:05 EDT Harding-Chamberlin 345-kV line trip, and came up with a valid solution.
- At 15:32 EDT, FirstEnergy's Hanna-Juniper 345-kV line tripped and locked out. The AEPR continued to malfunction.
- At 15:41 EDT, the lights flickered at FirstEnergy's control facility, because the facility had lost grid power and switched over to its emergency power supply.
- At 15:42 EDT, a FirstEnergy dispatcher realized that the AEPR was not working and informed technical support staff of the problem.

Findings to Date

The SWG has developed the following findings via analysis of collected data and discussions with energy companies and entities identified by the ESWG as pertinent to the SWG's analysis. SWG analysis to date provides no evidence that malicious actors-either individuals or organizations-are responsible for, or contributed to, the power outage of August 14, 2003. The SWG continues to coordinate closely with the other Task Force Working Groups and members of the U.S. and Canadian law enforcement and DHS/OCIPEP communities to collect and analyze data to test this preliminary finding.

No intelligence reports before, during, or after the power outage indicated any specific terrorist plans or operations against the energy infrastructure. There was, however, threat information of a general nature related to the sector, which was provided to the North American energy industry by U.S. and Canadian government agencies in late July 2003. This information indicated that al-Qaeda might attempt to carry out a physical attack against oil production facilities, power plants, or nuclear plants on the U.S. East Coast during the summer of 2003. The type of physical attack described in the intelligence that prompted the threat information was not consistent with the events of the power outage.

Although there were a number of worms and viruses impacting the Internet and Internet-connected systems and networks in North America before and during the outage, the SWG's preliminary analysis provides no indication that worm/virus activity had a significant effect on the power generation and delivery systems. Further SWG analysis will test this finding.

SWG analysis to date suggests that failure of a software program-not linked to malicious activity-may have contributed significantly to the power outage of August 14, 2003. Specifically, key personnel may not have been aware of the need to take preventive measures at critical times, because an alarm system was malfunctioning. The SWG continues to work closely with the operators of the affected system to determine the nature and scope of the failure, and whether similar software failures could create future system vulnerabilities. The SWG is in the process of engaging system vendors and operators to determine whether any technical or process-related modifications should be implemented to improve system performance in the future.

The existence of both internal and external links from SCADA systems to other systems introduced vulnerabilities. At this time, however, preliminary analysis of information derived from interviews with operators provides no evidence indicating exploitation of these vulnerabilities before or during the outage. Future SWG work will provide greater insight into this issue.

Analysis of information derived from interviews with operators suggests that, in some cases, visibility into the operations of surrounding areas was lacking. Some companies appear to have had only a limited understanding of the status of the electric systems outside their immediate control. This may have been, in part, the result of a failure to use modern dynamic mapping and data sharing systems. Future SWG work will clarify this issue.

Appendix A

Description of Outage Investigation and Plan 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.

This appendix outlines the process used to investigate why the blackout occurred and was not contained, and explains how recommendations will be developed to prevent and minimize the scope of future outages. The essential first step in the process was the creation of a joint U.S.-Canada Power System Outage Task Force to provide oversight for the investigation and the development of recommendations.

Task Force Composition and Responsibilities

President George W. Bush and Prime Minister Jean Chrétien created the joint Task Force to identify the causes of the August 14, 2003 power outage and to develop recommendations to prevent and contain future outages. The co-chairs of the Task Force are U.S. Secretary of Energy Spencer Abraham and Minister of Natural Resources Canada Herb Dhaliwal. Other U.S. members are Nils J. Diaz, Chairman of the Nuclear Regulatory Commission, Tom Ridge, Secretary of Homeland Security, and Pat Wood, Chairman of the Federal Energy Regulatory Commission. The other Canadian members are Deputy Prime Minister John Manley, 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 are Jimmy Glotfelty on behalf of the U.S. Department of Energy and Dr. Nawal Kamel on behalf of Natural Resources Canada.

U.S. Energy Secretary Spencer Abraham and Minister of Natural Resources Canada Herb Dhaliwal met in Detroit, Michigan on August 20, and agreed on an outline for the Task Force's activities. The outline directed the Task Force to divide its efforts into two phases. The first phase was to focus on what caused the outage and why it was not contained, and the second was to focus on the development of recommendations to prevent and minimize future power outages. On August 27, Secretary Abraham and Minister Dhaliwal announced the formation of three Working Groups to support the work of the Task Force. The three Working Groups address 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 are 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, a team of electric system experts was established to investigate the causes of the outage. This 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, vegetation and right-of-way management, transmission and reliability investments, and root cause analysis. The root cause analysis is best understood as an analytic framework as opposed to a stand-alone analytic effort. Its function was to enable the analysts to draw upon and organize information from all of the other analyses, and by means of a rigorously logical and systematic procedure, assess alternative hypotheses and identify the root causes of the outage.

Separate teams 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.

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 various work products to be prepared by the investigative teams. Drafts of these work products were reviewed and commented upon by the relevant Working Groups. These work products were then synthesized into a single Interim Report reflecting the conclusions of the three investigative teams and the Working Groups. Determination of when the Interim Report was complete and appropriate for release to the public was the responsibility of the joint Task Force.

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 independent system operators (ISOs) and electric companies affected by the blackout, and for the investigative team to be able to interview 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.

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, including 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 the Canadian Department of Natural Resources 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 works closely with his American Co-Chair, Secretary of Energy Abraham, as well as NERC and his provincial counterparts in carrying out his responsibilities. The Task Force will report to the Prime Minister and the US President upon the completion of its mandate.

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

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 (USDOE) 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.

The investigative team held three technical conferences (August 22, September 8-9, and October 1-3) with the 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. The team also requested information from the public utility commissions in the affected states and Ontario on transmission right-of-way maintenance, transmission planning, and the scope of any state-led investigations concerning the August 14 blackout. The team also commissioned a study by a firm specializing in utility vegetation management to identify "best practices" concerning such management in right of way areas and to use those practices in gauging the performance of companies who had lines go out of service on August 14 due to tree contact.

Data "Warehouse"

The data collected by the investigative team became voluminous, so an electronic repository capable of storing thousands of transcripts, graphs, generator and transmission data and reports was constructed in Princeton, NJ at the NERC headquarters. At present the data base is over 20 Gigabytes of information. That data consists of over 10,000 different files some of which contain multiple files. The objective was to establish a set of validated databases that the several analytic teams could access independently on an as-needed basis.

The following are 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.
- Materials provided by the above organizations in response to one or more data requests from the Investigation Team.
- Extensive review of all taped phone transcripts between involved operations centers.
- Additional interviews and field visits with operating personnel on specific issues in October, 2003.
- 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.
- Computer simulation and modeling conducted by groups of experts from utilities, reliability coordinators, reliability councils, and the U.S. and Canadian governments.

Sequence of Events

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 some variance 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 replicated system conditions on August 14 and the events leading up to the blackout. While the sequence of events provides a precise description of discrete events, it does not describe the overall state of the electric system and how close it was to various steady-state, voltage stability, and power angle stability limits. An accurate computer model of the system, benchmarked to actual conditions at selected critical times on August 14, 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 36 people involved at various different times with additional experts from the affected areas to understand the data.

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.

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 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 in any way 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.

Assessment of Right of Way (ROW) Maintenance

The Vegetation/ROW Team investigated the practices of transmission facilities owners in the affected areas for vegetation management and ROW maintenance. These practices were compared to accepted utility practices in general across the Eastern Interconnection. Also, the team investigated historical patterns in the area related to outages caused by contact with vegetation.

Root Cause Analysis

The investigation team used an analytic technique called root cause analysis to help guide the overall investigation process by providing a systematic approach to evaluating root causes and contributing factors leading to the start of the cascade on August 14. 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.

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 Dhaliwal regularly and provided weekly summaries from all components on the progress of the investigation. The leadership of the electric system investigation team held daily conference calls to address analytical and process issues through the investigation. The three Working Groups held weekly conference calls to enable the investigation team to update the Working Group members on the state of the overall analysis.

Root Cause Analysis

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 must be described in factual terms. Causal linkages must be established between the major event and earlier conditions or events. Such earlier conditions or events must be examined in turn to determine their causes, and at each stage the investigators must ask whether a 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.

Appendix B

List of Electricity Acronyms

BPA	Bonneville Power Administration
CNSC	Canadian Nuclear Safety Commission
DOE	Department of Energy (U.S.)
ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission (U.S.)
FRCC	Florida Reliability Coordinating Council
GW, GWh	Gigawatt, Gigawatt-hour
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
MVA, MVAr	Megavolt-amperes, Megavolt-amperes-reactive
MW, MWh	Megawatt, Megawatt-hour
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordination Council
NRC	Nuclear Regulatory Commission (U.S.)
NRCan	Natural Resources Canada
OTD	Office of Transmission and Distribution (U.S. DOE)
PUC	Public Utility Commission (state)
RTO	Regional Transmission Organization
SERC	Southeast Electric Reliability Council
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority (U.S.)

Appendix C

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

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 respond 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).

Automatic Operating Systems: Special protection systems, or remedial action schemes, that require no intervention on the part of system operators.

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 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 at any location. 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.

DC: Direct current; current that is steady and does not change with time.

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 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 Corporation: 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).

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 occur as random events, usually an act of nature.

Federal Energy Regulatory Commission (FERC): Independent Federal agency within the U.S. Department of Energy 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: Generall, 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 other 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.

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 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 designed 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. Load should not be confused with demand, which is the measure of power that a load receives or requires. 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 multiple 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.

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).

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 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.

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 "Active Power."

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). 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 in the ideal sense.

Real Power: See "Active Power."

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.

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.

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.

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.

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

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.

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.

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 *active power* flow. More precisely, a thermal limit restricts the sum of the squares of *active* 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.

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 of specified severity 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 person 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 1watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Appendix D

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 Interim 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 of the causes of the blackout that occurred on August 14, 2003. The report was written largely by four members of the Working Group (Joe Eto, David Meyer, Alison Silverstein, and Tom Rusnov), with important assistance from many members of the Task Force's investigative 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 attached page. Due to schedule conflicts, one member of the ESWG was not able to participate in the final review of the report and has not signed this transmittal letter for that reason.

Sincerely,

David H. Meyer		Alison Silverstein
David H. Meyer Senior Advisor U.S. Department of Energy Co-Chair, ESWG	Thomas Rusnov Senior Advisor Natural Resources Canada Co-Chair, ESWG	Alison Silverstein Senior Energy Policy Advisor to the Chairman Federal Energy Regulatory Commission Co-Chair, ESWG

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

Blaine Loper, Senior Engineer
Pennsylvania Public Utility Commission

Donald Downes, Chairman
Connecticut Department of
Public Utility Control

(not able to participate in review)
William D. McCarty, Chairman
Indiana Utility Regulatory Commission

Joseph Eto, Staff Scientist
U.S. Department of Energy
Lawrence Berkeley National Laboratory
Consortium for Electric Reliability
Technology Solutions

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

Jeanne Fox, President
New Jersey Board of Public Utilities

David O'Brien, Commissioner
Vermont Department of Public Service

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

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

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

Alan Schriber, Chairman
Ohio Public Utilities Commission

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

November 5, 2003

PREDECISIONAL

Mr. James Glotfelty
Senior Policy Advisor
Office of the Secretary
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 is the interim phase-one report of 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 the attached pages. This interim report is predecisional (not for public release) until you issue the Task Force interim report, and should be made available only to those individuals needing this information to support the Task Force activities.

Please provide any comments related to the Canadian nuclear plants to either Mr. Jim Blyth (613-995-2655; blythj@cnsc-ccsn.gc.ca), or 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 Interim Report Phase One

PREDECISIONAL

cc w/encl: Mr. James Blyth
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 Power Reactor 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 Interim Report of the Security Working Group (SWG) supporting the United States - Canada Power System Outage Task Force.

The SWG Interim Report presents the results of the Working Group's analysis to date of the security aspects of the power outage that occurred on August 14, 2003. 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

NATIONAL COMMISSION ON ENERGY POLICY

REVIVING THE ELECTRICITY SECTOR

Findings of the National Commission on Energy Policy

August 2003

National Commission on Energy Policy
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REVIVING THE ELECTRICITY SECTOR

Key Findings of the National Commission on Energy Policy

The National Commission on Energy Policy was founded in 2002 by the William and Flora Hewlett Foundation, and its partners—the Pew Charitable Trusts, the John D. and Catherine T. MacArthur Foundation, the David and Lucile Packard Foundation and the Energy Foundation. It is currently developing comprehensive recommendations for long-term national energy policy to be released in December 2004.

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Electric-industry restructuring has derailed. The massive blackout of August 14, 2003 certainly was not needed to underscore the point, but it adds urgency to the effort to find solutions. Wholesale markets continue to evolve slowly and erratically but are impeded by state-federal conflict, regulatory and legislative uncertainty, malfeasance, poor credit and outright collapses, of which Enron is only the most notorious. FERC's efforts to promote more efficient markets through regional transmission organizations and a wholesale market platform offer promise, but have generated confusion and opposition. In the last five years, increased generation competition has elicited more than 100,000 megawatts of gas-fired peaking and baseload capacity, which has contributed both to a period of relatively low wholesale prices in many regions and increased exposure to gas price volatility across the system. But competitors' losses have created substantial uncertainty about how quickly and on what terms capital markets will support additional investment throughout this sector. Indeed, investment in all categories of electricity infrastructure is down significantly, in part because of surplus capacity conditions in certain regions, but also because of uncertainty concerning which entities have the responsibility for identifying and making investments in the transmission and distribution networks, and uncertainties about how the associated costs will be recovered. A challenge in reviving these capital flows is to clarify prospects for cost recovery and reward: for example, when and on what terms will distribution utilities have the ability to enter into long-term contracts with generation service providers; how will distribution utility responsibilities interact with the opportunities created for competitive retail suppliers in states with retail competition; who has the responsibility for identifying needed enhancements to the transmission network; how will they be paid for securing them; and who will pay? The August 2003 blackout is a reminder of how much hinges on finding practical answers promptly.

Individual states have varied greatly in their willingness to introduce retail electricity competition, and their enthusiasm for federal policies designed to promote wholesale competition. Even in states that have opted for retail competition, efforts to expand it have generally halted in the wake of the Enron collapse and the California disaster. Large industrial customers often have benefited from retail competition, effectively exercising their ability to "buy wholesale" whenever prices are lower than the "safety net" of regulated rates that such states typically provide. These customers seldom seek "value-added" electricity service; rather, they seek the cheapest commodity prices and the shortest contractual commitments. Large customers contend that their continued exposure to some utility charges impedes the further development of these markets. Utilities contend that continued safety nets for the industrials have the same effect.

Small customers sometimes have benefited from rate guarantees in restructuring legislation, but they have received little direct benefit from retail competition itself. Because the pocketbook advantages have been insubstantial, many consumers find the choices associated with retail competition to be more of an annoyance than an advancement over past service offerings. Retail marketers have lost some billions in capital without developing a profitable, sustainable and distinct value-added product, although a few pioneers have made intriguing efforts to market products based on environmentally preferred generation sources.

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At the same time, it is often unclear who is responsible for assembling a diversified mix of short- and long-term resource commitments and other risk management tools, in order to sustain the economical and reliable electricity services that a healthy economy requires. Competitive models assume that decisions by market participants will replace resource planning by utilities or regulators. In practice, however, competitive models have retained -- whether in utilities, in regional transmission organizations or in the states themselves -- some residual responsibility for ensuring that electricity supplies remain adequate. In some restructuring models, customers unwilling or unable to choose a supplier have been provided with default options that influence the evolution of the market. These "carrier of last resort" options also fail to address either the real relationships between wholesale and retail markets or the complex issues involved in resource planning. Indeed, in California, events evolved such that from 1998-2001 utilities were required to supply power to retail consumers at frozen rates after losing the ability to enter into forward contracts for the power that they were obligated to deliver..

In states with traditional regulatory regimes, the regulated utilities that provide most resource procurement and management services generally do so based on longstanding cost recovery principles, with abundant downside risk and little or no prospect of gain regardless of the quality of their performance. In states with retail competition, the retail suppliers view long-term procurement by distribution companies as unfair competition, and the distribution companies face potential stranded cost problems or prudence reviews from regulators if they do make resource commitments. Yet failures to make such commitments may force expensive purchases in volatile short-term markets, which may result in adverse treatment by regulators.

Even in states that do not have retail competition programs, the threat of their introduction and stranded costs deters long-term commitments by investor owned utilities, even as risks of regulatory review make the alternative of short-term purchases look dangerous for utility shareholders. Utilities, regulators and wholesale suppliers alike are struggling with how states can regulate retail electric service provided by companies that operate in wholesale power markets that cross state lines. All parties are stuck between uncertain regulatory regimes, with no assurance about the rules that will determine commercial survival and success.

Finally, the electric industry's environmental footprint is significant, and a wide range of technologies and technology vintages means widely varying emissions and other impacts from the competitors for generation and grid investments. While there have been important reductions in some power generation pollutants, the sector's greenhouse gas emissions have been increasing more rapidly than those of the rest of the economy. National policy on greenhouse gases and other key pollutants remains uncertain, and states are beginning to act on their own initiative to reduce these emissions. This continuing policy struggle and growing jurisdictional tension creates an additional source of uncertainty for the industry, with serious implications for different technology options, electricity service costs, and environmental consequences of electricity production and transmission.

Overcoming these formidable challenges requires a balancing of the extent to which electricity is a commodity and a public service. Also needed are an evaluation of the benefits of

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competition and other mechanisms for achieving public utility goals, and an integration of the flexibility of spot markets with the increased certainty of planning. To complicate matters further, key decision-makers at different levels of government are at odds over who should make these decisions and how.

The Commission sees an urgent need to address and help resolve these issues. Both state and federal regulators have vital and complementary roles to play in providing consumers with the benefits of properly structured electricity markets. Within the context of pending regulatory and legislative proposals at both federal and state levels, we aim to help define those roles and to offer a vision for revitalizing both wholesale electricity markets and broader electricity-resource procurement and management responsibilities. In the process, we will explore the most promising ways to encourage appropriate electricity-resource and grid investments.

Absent the prospect of retail competition, of course, this would be an easier problem to solve.[1] Under regulatory oversight, distribution companies could have relatively well defined retail supply obligations, met through some combination of wholesale contracts, demand-side investments and ownership of generation assets. A crucial issue, then, is how to think about retail competition: if we are going to have it, how can we make it work and speed the transition? If instead we prefer to reject retail competition, how do we make that decision credible enough for distribution companies and others to take it to the bank? If different states and regions choose different models, how will those variations intersect with national policies that favor more standardization for wholesale power markets and the role of transmission systems (and regional transmission organizations) in enabling them?

Finally, no assessment of our electricity challenges would be complete without careful attention to the system's vulnerability to terrorist attack. Much of the electricity infrastructure is in private hands, so protecting that infrastructure will require a strong government-private sector partnership. Although the grid is more resilient than many may appreciate, some equipment has long replacement lead-times and constant vigilance is essential to guard against potential disruption of the grid control systems. Attacks could be either cyber-based or physical, or some combination of the two. These issues deserve, and are getting sustained attention from, institutions like the Department of Homeland Security, the Department of Energy, the Federal Energy Regulatory Commission, the National Academies, numerous state agencies, and the North American Electric Reliability Council. The Commission's recommendations below reflect and reinforce their vital work. At the same time, although it has not been linked to sabotage, the August 2003 blackout is a reminder that reliability concerns demand strong enforcement of mandatory reliability standards as a replacement for today's overburdened voluntary system; the Commission adds its voice to those who have been urging Congress to take specific action here.

[1] Other important questions include whether load serving entities should be generation owners or not, and whether distribution companies will retain ownership of transmission. A central and still unresolved issue is whether wholesale competition can flourish (or flourish enough) in a world that includes vertically integrated utilities (i.e., utilities that own generation, transmission and distribution assets).

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THE COMMISSION'S INITIAL RECOMMENDATIONS

The Commission supports an energy policy that recognizes both the quarter-century march toward increased competition in electric generation and wholesale markets and the value of traditional modes of regulatory authority. A fundamental assumption is that the wholesale electricity business is largely a competitive commodity business. So too is the retail supply of electricity to very large customers, including industrial customers and some national chains. However, the retail supply of electricity to other customers is, for the foreseeable future, likely to remain a service-oriented business with major public policy implications. In this context, electric distribution and transmission companies have both special opportunities and special obligations. As the federal government and the states attempt to resolve the tensions inherent in promoting competition and customer choice, multiple paths may be found to widely shared equity, environmental and economic objectives.

These recommendations constitute a framework that the Commission presents as a prototype for progress in accommodating diverse needs and goals:

FOR STATE REGULATORS AND BOARDS OF CONSUMER-OWNED UTILITIES:

1. Retail distribution should remain a responsibility of utilities under state and local regulation, along with electric energy resource portfolio management for residential and small business customers (and any larger customers who choose regulated portfolio services).[2] If customers, especially large users of electricity, are permitted to opt out of regulated portfolio service and to make their own choices in retail electric markets, they should be allowed to return to regulated service only on terms that hold harmless other customers and the regulated portfolio manager. For small customers in states that opt for retail electricity competition, schedules should be established to allow for orderly provision of retail choice opportunities in phases across service territories, with all small customers having opportunities to choose alternative portfolio managers no less than every five years.

2. Large customers who choose regulated portfolio service should be required to execute long-term contracts with the utility portfolio manager. Large customers who do not opt for regulated portfolio services should make their own way in the competitive retail markets.

3. State regulators and boards of consumer-owned utilities need to focus more on incentives for good portfolio management service. Options include systems of performance-based regulation for regulated portfolio management (and other) services provided by retail distribution companies, based on objective benchmarks, and incentives for managers and

[2] As indicated in the introductory section, by "electric resource portfolio management" the Commission means "assembling a diversified mix of short- and long-term resource commitments and other risk management tools, in order to sustain the economical and reliable electricity services that a healthy economy requires."

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(where applicable) shareholders reflecting reasonable measures of net benefits delivered to customers. Regulated distribution companies can be compensated independently of increased electricity sales (for example, utilities' fixed-cost recovery can be made independent of retail electricity use, through the mechanism of small periodic upward or downward adjustments in distribution rates). For purposes of meeting portfolio management responsibilities, reliable load reductions and reliable generation, including small-scale "distributed" generation at or near load centers, should all be investment candidates. The goal should be to hold regulated portfolio managers accountable but also to avoid complex regulatory review processes.

FOR THE FEDERAL ENERGY REGULATORY COMMISSION:

4. The Commission supports FERC's efforts to ensure nondiscriminatory transmission operations and nondiscriminatory access to grids and wholesale markets, with appropriate deference to the needs of states that have not adopted retail competition and states' crucial role in ensuring resource adequacy. Congress should authorize the extension of those requirements to all transmission regardless of who owns it. The Commission believes that these policies are needed to revitalize competitive wholesale electricity markets. Wholesale market participants should win or lose based on their ability to maximize operating efficiencies under a deregulated price regime untainted by exercises of market power

5. To improve system security and reliability, the national electricity system needs to maintain dispersed and well guarded stockpiles of critical equipment with long replacement lead-times, and to standardize such equipment wherever feasible. Prompt attention should also be given to ensuring the security of Supervisory Control and Data Acquisition (SCADA) systems. Also important are joint government-private sector efforts to complete the studies necessary to mitigate the effects of and accelerate recovery from terrorist attacks. The costs of these efforts, and other costs involved in improving grid security, should be shared system-wide on a competitively neutral basis, through uniform charges on transmission use administered by the FERC. In view of the national importance of this objective and its relatively modest cost when spread across the nation's electrical grid, Congress should provide for the collection of these charges notwithstanding state-mandated retail rate freezes.

FOR CONGRESS:

6. Both societal and generation-sector interests would benefit substantially from more coordination and greater certainty regarding targets and timetables for achieving long-term environmental objectives. Accordingly, for all categories of power plant emissions that it considers appropriate subjects of regulation, Congress should establish an integrated regulatory structure that (1) establishes a firm multi-year schedule of phased emission reductions that accommodates both environmental and system reliability needs;

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and (2) uses market-based mechanisms to the maximum extent feasible to minimize compliance costs and encourage innovation.

7. Congress also should tighten energy efficiency standards wherever practicable and cost-effective, in view of the substantial environmental and economic costs associated with unnecessary use of energy.

8. The August 2003 blackout was a terrible reminder that the system of voluntary compliance with non-binding reliability rules for electricity grids is breaking down across North America. Congress should approve widely supported proposals to make such reliability rules mandatory and enforceable, when promulgated by a FERC-approved North American electric reliability organization working with regional bodies accountable to all owners, operators and users of bulk power systems, and with ultimate oversight responsibility vested in the Federal Energy Regulatory Commission. See also item 5 above.

FOR ALL DECISION-MAKERS:

9. Wholesale electric markets work best when they are liquid and transparent, for real time, day ahead and long-term products. The Commission supports FERC's proposals for real-time and day-ahead wholesale markets, along with state-level policies designed to ensure that such price signals are much more effectively communicated to large customers or aggregators at the retail level. More transparency for spot market prices and volumes of electricity trading, with reporting as close as possible to real time, are urgent priorities.

10. While the Commission is encouraged by the emergence of innovative technological solutions to transmission reliability and congestion problems, we agree that inadequate investment in transmission infrastructure is a significant and growing national problem. Transmission owners should be challenged to identify and consider all potentially cost-effective solutions to congestion and reliability problems, including targeted demand reductions, replacements of existing facilities with better equipment and new technology, and new facilities. No single solution will suffice; we need a portfolio that includes using new technology as well as constructing new transmission lines. FERC should also clarify which entities are responsible for identifying and making transmission investments, how they will be paid, and who will pay the associated costs. Options for encouraging cost-effective investment include higher rates of return for approved measures, increased certainty of recovery, and performance-based rewards that share system savings between shareholders and users. In addition, confusion and controversies created by FERC's interest in merchant transmission investment, and ambiguities about the practical meaning and application of the "participant funding" concept, are discouraging investment and must be clarified and resolved.

11. Congress, FERC and state regulators should encourage interconnected electricity systems to undertake more regional resource and grid enhancement planning.

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12. Urgent action is needed to revive the electricity sector's research and development investments, always low by any reasonable standard and down by more than three-fourths in real terms over the past two decades. The Commission favors supplementing the federal budgetary contribution with a combination of federal tax incentives and state-approved utility investments, recovered as small charges on electric distribution, such as those that created the Electric Power Research Institute.

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The following Commissioners join in support of the recommendations stated herein:

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John W. Rowe
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Phillip R. Sharp
Senior Advisor, Lexecon, Inc.; Senior Policy Advisor, Van Ness Feldman; Former U.S. Representative, IN

Linda Stuntz
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Susan Tierney
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R. James Woolsey
Vice President, Booz, Allen, Hamilton; former Director of the Central Intelligence Agency

Dr. Martin B. Zimmerman
Group Vice President, Corporate Affairs, Ford Motor Company

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***Special Concurrence from Commissioner Sharon Nelson**
Senior Assistant Attorney General; Chief, Consumer Protection Division, Washington Attorney General's Office

I respectfully concur. The commission's statement is a committee work product on a complex subject. Like all such collegial efforts, the paper suffers from compromises and code words. I worry that some of the less obvious compromises will be used in Congressional and other policy debates for purposes not intended by any commissioner. However, the report contains many meaningful recommendations which advance the policy debate currently underway in the nation's capital and in other policy venues.

The electricity sector provides an essential infrastructure for assuring the public safety, health and welfare. This report recognizes this practical reality and the significant need to re-establish some semblance of predictability for the electricity sector. It also encourages important efforts to address national security concerns, promotes coordinated regulation of all power plant emissions, encourages greater emphasis on energy efficiency and supports much needed technology R & D. The report also recognizes that other values besides market values still vitally affect the electricity industry and are affected by it. For these reasons, I support the report, despite the concerns described below.

I reside in a region of the country which has suffered from "market designs" we sought to avoid. In my view, markets are not designed. They may evolve, they may be influenced by public policy but they are not the product of legislative or regulatory mandates. This report should be understood as merely early input on a still fitfully evolving "competition" policy in electricity.

The report refers to the nation's quarter century trend toward competition in markets formerly viewed as de jure or de facto monopolies and implies that this forward march should not be interrupted by "inappropriate" state retail competition policies. In my opinion, there were good reasons for the electricity industry to be the last of the network industries to experience "restructuring." As opposed to the transportation, banking, or telecommunications industries, the preconditions which characterized the other sectors' reformations (such as ease of access to capital markets, freedom of entry, well understood rules about interconnection) did not exist in the vertically integrated electricity industry. Indeed, one major difference here is the ownership structure of the industry. As opposed to the natural gas industry or wireline telecom industry, the electricity industry is characterized by suppliers which are not investor owned. For example, in Washington State, two thirds of retail electricity sales are provided by customer or municipally owned providers. Traditional institutional oversight for this complex industry is not the same as the parallel natural gas or telecom markets "enjoyed," making legislative and regulatory initiatives even more complicated. The phrase "ensuring a level playing field" is a hackneyed one, but this common sense goal is practically not achievable for the entire electricity industry in the nation's current electoral-political environment. In my view, in 2003, the nation needs a far more thoughtful analysis of why the experiments in Pennsylvania, California, the United Kingdom and Texas are succeeding or failing. Once we draw some lessons from empirical studies, then maybe some more far reaching and sensible policy reforms would flow.

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I have specific concerns with recommendations 9 and 10. I am concerned that they provide too much deference to the Federal Energy Regulatory Commission which at this point does not manifest the institutional competence to warrant such trust, do not recognize regional differences or operational differences between thermal and hydro-electric systems, and are at once vague and overly prescriptive.

Despite these concerns, I support a significant majority of the paper's recommendations. The debate over the future direction of our nation's electricity system is fundamentally stymied. The hard work and significant agreements reached by our expert and diverse Commission causes me to conclude that the overall report advances the national policy debate. For this reason I concur.

SPECIAL NOTICE – Leo Gerard, President of the United Steelworkers of America (USWA)

Leo Gerard joined the National Commission on Energy Policy after the bulk of work on this paper was completed. As a result, Mr. Gerard takes no position on the paper's content or recommendations. The issues raised in this paper are of significant interest to Mr. Gerard and to the USWA. Mr. Gerard will work actively in the coming months to ensure that the NCEP enjoys the benefit of the labor perspective when crafting its final recommendations.

Contributing Factors to the Series of Outages on August 14, 2003

A White Paper

Product ID 1009192

September 23, 2003

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CONTRIBUTING FACTORS TO THE SERIES OF OUTAGES ON AUGUST 14, 2003

White Paper – September 23, 2003

Objective of the Study

At the request of FirstEnergy Corp., EPRI performed an independent assessment of factors contributing to the series of outages on August 14, 2003 , which affected millions of electricity customers in the United States and Canada. This white paper, prepared by EPRI, describes that assessment. Over a period of three weeks, the study focused on data collection and analysis in two areas: (1) systemic factors that may have made the power system in this region particularly vulnerable to outage, and (2) specific operational and performance factors that may have helped precipitate the August 14 outage. It is important to recognize that, because this study was performed in a such a short timeframe and was based on data from only FirstEnergy Corp. and public sources these are only preliminary observations by the EPRI team. Such observations, however, may be helpful to the official U.S./Canada Power Outage Task Force in identifying areas deserving additional data collection and investigation and larger systemic issues requiring more thorough analyses to determine any appropriate corrective action.

Key Findings

A number of systemic issues may have contributed to the chain of events leading up to the August 14 outage. These need to be further explored with an eye toward preventing large-scale regional outages in the future. These include the following:

- Lack of understanding of VAR reserves in the region and the adjacent regions, coupled with the impact of lack of financial incentives for entities to provide adequate VAR support. (VAR is shorthand for reactive power, which is the additional power required for maintaining voltage stability when serving certain kinds of load, such as motors, air conditioning, and fluorescent lights.) To understand the overall outage and develop appropriate mitigation recommendations, it is important for the U.S. / Canada Power Outage Task Force to devote more resources to the collection of all relevant information and incorporate it into models and analyses.
- Insufficient "visibility" of power flow conditions over the entire region, coupled with inadequate coordination, control and communication of the power system on a regional basis.
- Insufficient understanding of new power flow patterns caused by increased wholesale power transfers resulting from industry restructuring.
- Lack of real-time regional and interconnection-wide power flow models for anticipating changing flow patterns and the formation of new bottlenecks.

In addition, a number of specific operational issues that occurred on August 14 may have contributed to the outages and are deserving of further analysis. These include the following:

- Power flows from merchant plants in southern Ohio, providing power to the north, heavier than on prior days without adequate region-wide VAR support to maintain voltage stability in the region.
- An unexplained cessation of alarms at FirstEnergy between 2:35 PM and 3:30 PM EDT, August 14. The alarm failure may have handicapped the operators at FirstEnergy. However, other control areas also reported alarm performance problems as well as data communications problems, which may have hampered Internet access and energy management systems (EMS) hardware and software performances. These may be systemic issues worthy of further review along with the communication and coordination among regional reliability coordinators.
- An unusual number of unexplained "spurious" trips of power lines before they were fully loaded to their thermal limit. Further investigation is needed to determine all causes for the trips, e.g., if they sagged into trees and shorted out or if the lines tripped for overloads, under-voltage, over-excitation, under or over-frequency, etc., to determine any improvements on protection philosophy and practices, including wide-area protection coordination.

Study Approach

In identifying the contributing factors for the disturbances that occurred after 4 PM (all time is EDT) on August 14, 2003, the EPRI study team decided to examine the system conditions starting from mid-morning of the day of the disturbance.

Collect Data and Synchronize Time Stamps

The study process involved three steps. The first was to synchronize the time stamps of the different sources of recorded data in order to precisely determine the timings of all the disturbances recorded by FirstEnergy. The majority of data for this analysis was data archived by the MISO energy management system (EMS) in 30-second time increments. Archived data from the FirstEnergy EMS is primarily limited to integrated hourly average data, although digital fault relay (DFR) and other information used is captured at sub-cycle resolution. Actual voltages at a number of FirstEnergy busses, and MW and MVAR flows on a number of lines, were collected and correlated. Data in the Cleveland area was limited.[1] Data from FirstEnergy concerning the adjacent operating regions was limited. Because the sequence of events on August 14 occurred over a wide area of the Eastern Interconnection, the lack of data about the grid beyond the FirstEnergy service areas limited the team's ability to make definitive conclusions.

Conduct Analysis to Understand Events

The second step, after collecting data, was an independent data review and analysis to obtain a better understanding of the sequence of events. This effort benefited in part from the timelines developed by various parties which were released to the public. The work involved reviewing the geographical locations and the timing of events and analyzing

[1] The MISO EMS directly receives real-time RTU data from FirstEnergy directly through the NERC Interregional Security Network (ISN), and should have these data in its archive.

available data for indications of whether the events might have been either related or purely random and independent. The team reviewed four primary areas of data, (a) MW, MVAR and % duty line flows, (b) voltages, (c) system frequency, and (d) alarm system reports and operator telephone logs.

Deliver Insights and Observations

The third part of this study was to synthesize the preliminary observations from the independent review and analysis into a set of potential contributing factors that may help explain the series of events on August 14, 2003. This white paper presents some of these key insights and observations. The information that follows is organized temporally as the events unfolded.

Initial Conditions Preceding 12:00 Noon Eastern Daylight Time

As noted in the last part of the paper, the data received suggests that the events of August 14 were not independent random coincidences. Therefore system conditions and the sequence of events may be viewed in that context.

Typical Summer Weather – No Serious Adverse Conditions (on the surface)

On the surface, August 14, 2003 was a typical summer weekday. There were no extreme weather conditions. Certain regions experienced relatively high temperatures while other regions were cooler. Temperatures were moderately high in the Eastern U.S. The temperature in Canton, Ohio, peaked at 87° F at 3 PM (humidity 48%, and heat index of 89° F, cloud coverage 30%). Ontario was facing rising temperature over the previous two days. The high temperature in Toronto was 88° F, following a high of 85° on August 13.

On average, Ontario was a net power exporter throughout the daytime periods in July 2003.[2] Between August 1 and August 13, Ontario exported at night and imported less than 500 MW during the daytime. On August 14, from the same data source, Ontario's scheduled import was about 2000 MW at 1 p.m. EDT and increased to about 2300 MW by 3 PM EDT.

As a result of these conditions, the wholesale power transfer pattern on August 14, 2003 in Ohio was essentially from west to east and from south to north. This is in contrast to the typical flow pattern, which is from north to south and west to east.

Transmission Lines and Generators out of Service on August 14

A number of generating units and transmission facilities were out of service for scheduled maintenance on August 14 in the Eastern Interconnection (see Table 1 for a partial list of transmission lines and generators which were out of service on August 14).

[2] Based on NERC TagNet data.

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Table 1 – Partial List of Transmission and Generation Facilities
Out of Service for Scheduled Maintenances Near the Affected Areas

Transmission Lines and Equipment	**Generators (Capacity, MW)**
FirstEnergy: • Fox Q-1-FX-C 138 Cap Bkr • Eastlake 62-EL-T 345/138 kV transformer •	**FirstEnergy:** • Davis Besse (883) • Eastlake unit 4 (240) • Sammis unit 3 (180)
IMO: • B3N (1 of 4 ties to Ontario) • J5D (phase shifter capability) • L51D (phase shifter)	**IMO:** • Atikokan (200) • Pickering unit 7 (500) • Nanticoke unit 1 (500) • Lakeview 1 (300) • Lakeview 2 (300)
PJM: • Linden - Goethals • Warren – Falconer 115 kV line • Plymouth – Whitpain (220-14) 230 kV line • Bath County – Valley 500kV line • Juniata #1 Transformer 500/230 kV • Dickerson-Dickerson H 23103 & 23104 230 kV lines	**PJM** • Keystone 2 (850) • Hudson 1 (383)
AEP (Not available)	**AEP** • Cook 2 (1060) • Tanners Creek 4 (500) • Glen Lyn 6 (235) • Conesville 5(375) • Gavin 2 (1300) but switched back @ 12:05 PM

In this day-ahead look, no apparent inadequacy existed between the MW generating capacity and loads, and between generating schedules and transmission capabilities in the Eastern Interconnection. However, unavailable generating units imply a decreased reactive capability to regulate system voltages, and perhaps reduced dynamic reactive reserves. The industry generally lacks timely, accurate data on the amount of dynamic and static reactive capacities on line over a wide area at any time, including the amount of reactive reserve available in the different parts of the Eastern Interconnection. Consequently, the EPRI project team could make no definitive statement about the available voltage support capability in the entire Eastern Interconnection on August 14,

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2003. However, as shown in the analysis later in this paper, this subject deserves further investigation.

Independent Power Producers

The operation of independent power producers in Ohio and Indiana on August 14, 2003 may have been one contributing factor in the sequence of events. Based on public information at the Ohio Power Siting Board (OPSB), one new 850 MW combined cycle merchant power plant at Waterford, Ohio began commercial operation on August 6, 2003. A second merchant plant (620 MW), also at Waterford, Washington County, Ohio, was in operation since about September 2002. A third merchant plant, Hanging Rock located in Ironton, Ohio, had a second combined cycle unit ready for commercial operation on July 14, 2003 after its first unit was declared to the OPSB as being ready for commercial operation on June 10, 2003. Its total capacity is 1240 MW. Altogether, the total generating capacity from these three merchants, all located in the southeastern part of Ohio, was 2710 MW, of which 1470 MW was new generation. The reactive support and voltage control capability available from these plants, and other generation, is unknown at this time. From the NERC TagNet data, there appeared to be no scheduled sales from the Waterford plant until August 14, 2003 when it was scheduled to start generating at 5 AM EDT with output reaching about 800 MW through most of the day (see Figure 1).

In Indiana, on August 14, 2003 at 13:15 EDT, the merchant plant at Wheatland was involved with an overload and system voltage problem near Gibson, Indiana, according to the MISO operator phone transcripts[3]. In addition to these merchant plants, there may have been other relatively new merchant plants in various parts of the Eastern Interconnection operating on that day. The scheduling and actual operation of these merchant plants, including automatic voltage control and VAR support, is generally not well known by grid operators because of commercial sensitivities and FERC regulation, unless the merchant plants are under direct contract and legal obligation to the connected grid to provide such ancillary services. This lack of information on the independent power producers was likely a contributing factor to the speed of grid operator response to emergencies on that day. From analyzing the NERC TagNet data, the schedules of the IPPs in southeastern Ohio and those of certain control areas on August 14, 2003 were computed. Figure 1 shows these schedules. Readers are cautioned against concluding that these were the actual generation or net interchanges that took place. Data on the actual generation and net interchanges should be collected from all control areas and all IPPs in the Eastern Interconnection before drawing such conclusions.

[3] Available from the House Committee on Energy and Commerce web site.

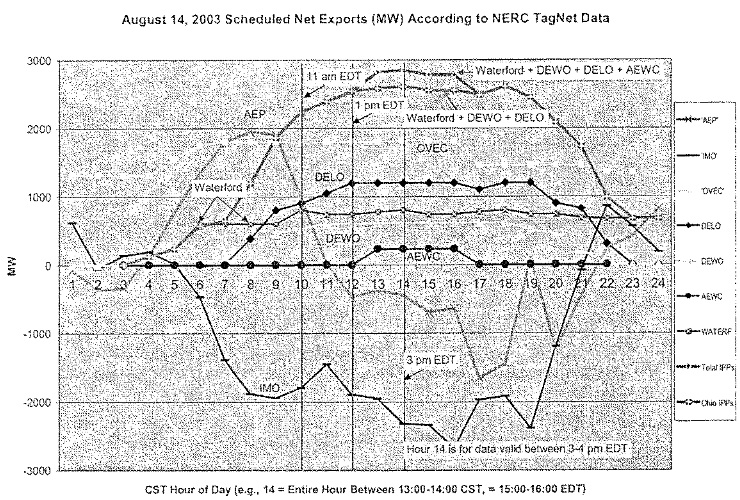

Figure 1 – Net Schedules of IPPs in southeastern Ohio, AEP, OVEC and Ontario (IMO) on August 14, 2003 From NERC TagNet Data (DELO = Hanging Rock, DEWO = Washington, AEWC = Wheatland)

NERC uses Central Standard Time (CST) for the IDC and for E-tags even during daylight saving time. Thus the original data in Figure 1 were reported in CST.

As shown in Figure 1, Ontario (IMO) was importing on August 14, 2003 and its scheduled import continued to increase between 12 noon and 3 PM EDT. The total scheduled output of the three merchant plants in southeastern Ohio ramped up rapidly starting at 8 AM and peaked at 2600 MW between 1 PM and 3 PM EDT. From about 11 AM, AEP's schedule showed a rapid reduction in its export, by an amount of about 2400 MW.

Sequence of Events on August 14, 2003

As we note later, the issue of reactive reserve margin in all or parts of the Eastern Interconnection deserves further investigation. This could have contributed to voltage support in a wide area not being efficiently achieved. The voltage issues noted in the following sequence of events may be viewed in that context.

Between 10:00 and 11:59 EDT

- The electrical operator at FirstEnergy's Eastlake plants reported that system voltage problems were experienced "throughout the morning".

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- The EPRI team examined voltages around the system for different times of the day. At 11:00 AM, a voltage snapshot around the FirstEnergy system showed, as expected, that the voltages were higher next to the large power plants and trended lower towards the load centers. In particular, several locations appeared to have relatively low voltages (both 345 kV and 138 kV levels) than expected when compared to other busses. Some of these anomalies may be attributed to calibration of the Capacitive-Coupled Voltage Transformers (CCVT) and Potential Transformers (PT).
- At approximately 11:54 Cinergy reported to MISO that its Bedford to Columbus 345 kV line had tripped, resulting in the loss of a 230 kV line segment from Bloomington to DeNoye Creek.

Actual flows (MW, MVAR) measured around the affected area at 12:00 are shown in Figure 2. The dark bars represent MW flows. The lighter color bars represent the MVAR flows. Negative numbers represent flows from the second location listed to the first. Blanks, e.g., AEP-OE, AEP-TE, etc., represent data that were not available to EPRI. The purpose of Figure 2 and similar subsequent Figures is to show the import or export of both MWs and MVARs into or out of the FE service areas with its neighbors. In Figure 2, MVAR was flowing from FE's Ohio Edison area into Duquesne (DQE).

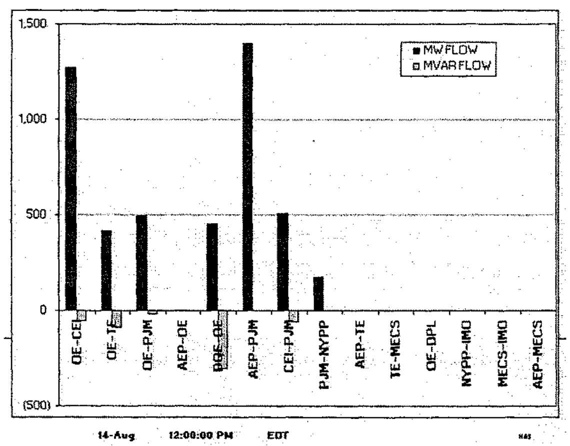

Figure 2 – Actual Flows (MW and MVAR) in the Affected Areas at 12:00 PM

In Figure 2 and subsequent similar Figures, the FirstEnergy areas include OE (formerly Ohio Edison), CEI (formerly Cleveland Electric Illuminating), and TE (formerly Toledo Edision); DQE is Duquesne, NYPP is NY ISO (formerly New York Power Pool), MECS is the former Michigan Electric Coordinating System, DPL is Dayton Power & Light, and IMO is Independent Market Operator (Ontario).

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Between 12:00 and 12:59 EDT

- 12:00 – Based on data from the historical NERC TagNet for all the electronic tags submitted to the NERC Interchange Distribution Calculator (IDC), the total IPP generation in SE Ohio from Waterford, Washington, and Hanging Rock was scheduled at 2540 MW, ramping up briskly starting at about 8:00 AM.
- 12:00 – NERC Reliability Coordinators' conference call activated a lowered reference frequency for the Eastern Interconnection for time error correction.
- 12:04 – FirstEnergy received alarms of low voltages (below 327.8 kV or 0.95 per unit) from Harding.
- 12:05:44 – Conesville Unit 5 (rating 375 MW) tripped.
- 12:25 – FirstEnergy received low voltage alarms from Inland, Fox, and Harding.
- Starting at about 12:30, a noticeable and gradual decline in voltages occurred in several buses in the FirstEnergy area. For example, by 13:00 the voltage for the Star 345 kV bus (a considerably stiff bus with four 345 kV lines and a number of 138 kV lines) had dropped by over 1% relative to its voltage at 11:00 AM (see Figure 3). It can be seen from Figure 3 that the voltage degradation at Star 345 kV was halted at 1:15 PM, corresponding to the increase in VARs from Sammis at that time (see Figure 3). That increase follows the System Control Center (SCC) request to increase voltage support from all generating plants. During this period, there was serious voltage degradation in the Cinergy area and at the same time the total generation output at Gibson was high, and the Bedford to Columbus line tripped. This voltage degradation and correction at 1:15 PM are also visible on International Transmission Company (ITC)'s Monroe 303 bus, as can be seen in Figure 4.
- 12:46 – A Level 1 TLR was called on the flow gate from Ghent to Batesville due to heavy flow from Kentucky into Indiana. MISO operators were simultaneously monitoring that situation and the Columbus-Bedford situation.
- 12:51:55 – The Dumont 765 kV reactor opened (responding to a need to support voltage in the AEP system with that action)[4].

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[4] The significance of this switching cannot be verified without data to ascertain whether this was an isolated event or an indication of a wide-area voltage problem.

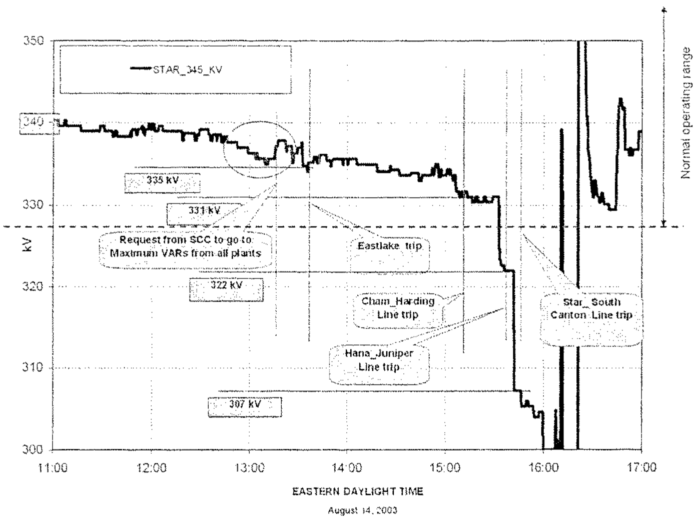

Figure 3 – Voltage vs. Time at Star 345 kV Bus on August 14, 2003

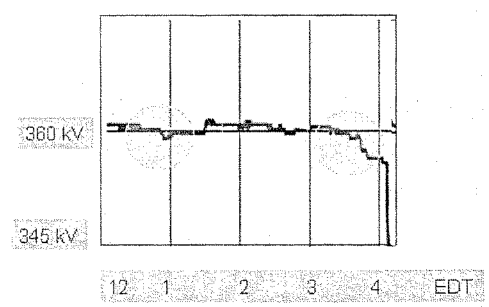

Figure 4 – Voltage vs. Time at International Transmission Company (ITC)'s Monroe 303 Bus (close to FE) on August 14, 2003

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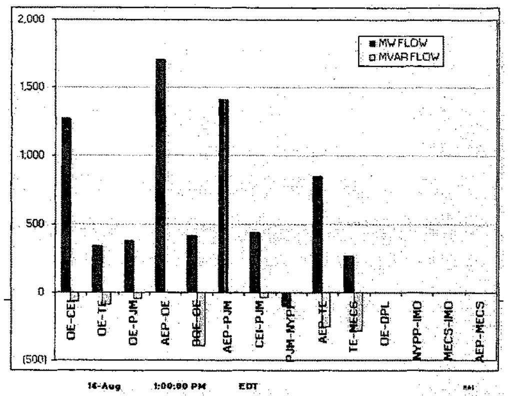

Figure 5 – Actual Flows (MW and MVAR) in the Affected Areas at 1:00 PM
Total FE MVARs = 286 Net Export
(Note that AEP-OE MVARs = -1; Missing MVARs are AEP-PJM, PJM-NYPP, OE-DPL, NYPP-IMO, MECS-IMO, AEP-MECS)

Between 13:00 and 13:59 EDT

- 13:00 – The total IPP generation in SE Ohio was scheduled at 2585 MW. The actual MW and MVAR flows are shown in Figure 5.
- 13:00 – Voltage at Star 345 continued to decline.
- 13:02 – Gavin (AEP, 1300 MW) went on line.
- 13:10 – The system Control Center (SCC) at FirstEnergy made a request to all FE power plants to increase voltage support. At Sammis the operators increased the set point and the machine was left on automatic (see Figure 6).
- 13:14:04 – Greenwood Unit 1 (rating 785 MW) tripped.
- 13:16 (approx.) – Cinergy and MISO noted that the Wheatland plant had synchronized to the system and was generating about 100 MW.
- 13:23 – Mone 1, 2 (300 MW) went online.
- 13:30 – In discussing about Wheatland, the MISO operator told the Cinergy operator,[5] "We're aware that when they're bringing their generation up, it's dropping the voltage. That's because they're sucking in more VARs than they're able to put out with their unit. I think that they can only put out 60 VARs (probably meaning MVARs), but they're sucking in close to 300, or not sucking in, but the voltage is dropping relative to that amount."
- 13:31:34 – Eastlake Unit 5 (EL5) (rating: 615 MW) tripped, due to MVAR runback and subsequent switch from manual to automatic operation to increase the VAR output. Immediately after EL5 tripped, as to be expected, Perry

[5] Transcripts of recorded telephone conversations at MISO on August 14, 2003 available at http://energycommerce.house.gov/108/Hearings/09042003hearing1062/hearing.htm

increased both real and reactive power to the Cleveland area. (See Figure 6.) Flows on the lines to the Cleveland exhibited increases in MW and MVAR loadings.

- 13:34 – FirstEnergy initiates Automatic Reserve Sharing in response to the loss of Eastlake.
- 13:44 – Mone 3 (150 MW) went on line

At 13:00, voltages in FirstEnergy's system continued to decline. At about 13:10, voltages started to climb. After Eastlake Unit 5 tripped, the voltage dropped. For example, the Star voltage came down to about 98.5% and then stabilized until about 14:00.

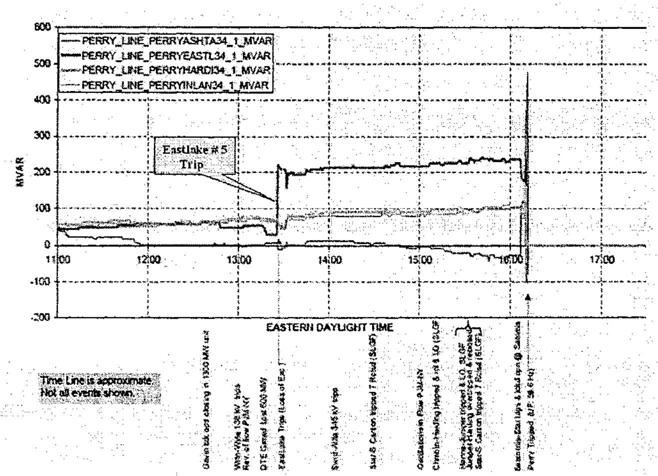

Figure 6 – Reactive Power from Perry Following the Tripping of Eastlake #5

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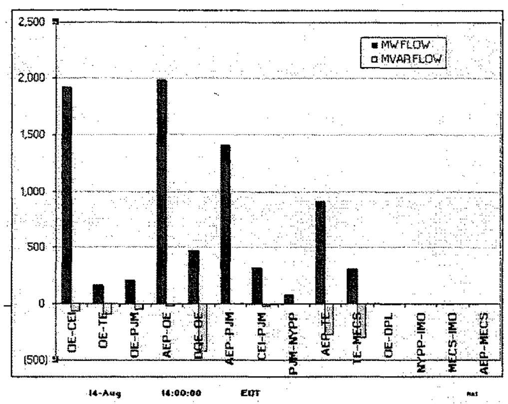

Figure 7 – Actual Flows (MW and MVAR) in the Affected Areas at 14:00
Total FE MVARs = 340 Net Export

Between 14:00 and 14:59 EDT[6]

- 14:00 – The total IPP generation in SE Ohio was scheduled to peak at 2611 MW and the MW and MVAR flows in the affected areas are as shown in Figure 7.
- 14:02 – Stuart to Atlanta 345 kV line tripped[7]
- 14:48 – Mitchell 1 (800 MW) controlled shutdown

At 14:10, voltages in FirstEnergy resumed their decline. By about 14:45, the Star voltage was stabilized at 335 kV, or about 98.5% of its 11:00 AM value.

Between 15:00 and 15:59 EDT

- 15:05:41 – Harding-Chamberlain 345 kV tripped for a fault condition.
- 15:32:03 – Hanna-Juniper 345 kV tripped, Star voltage declined by 18 kV to 322 kV, or 94.7% of its 11:00 AM magnitude
- 15:41:33 – Star-South Canton 345 kV tripped, loading about 1272 (SE rating = 1383 MVA) Star voltage declined by 33 kV to 307 kV, or 90.3% of its 11:00 AM magnitude
- 15:42:53 – Cloverdale-Torrey 138 kV tripped. Loading was 354 MVA (SE Rating 245 MVA)
- 15:45:33 – Cloverdale-Canton Central tripped (see Figure 8). Loading on this line jumped after Star-South Canton line tripped. Canton Central-Tidd 345 kV tripped due to breaker failure at Canton Central.
- At 15:55 – Star voltage had declined by 37 kV relative to voltage at 11:00 AM

[6] This sequence is not all inclusive as 138 kV lines generally are not included.
[7] From DOE-NERC Time line

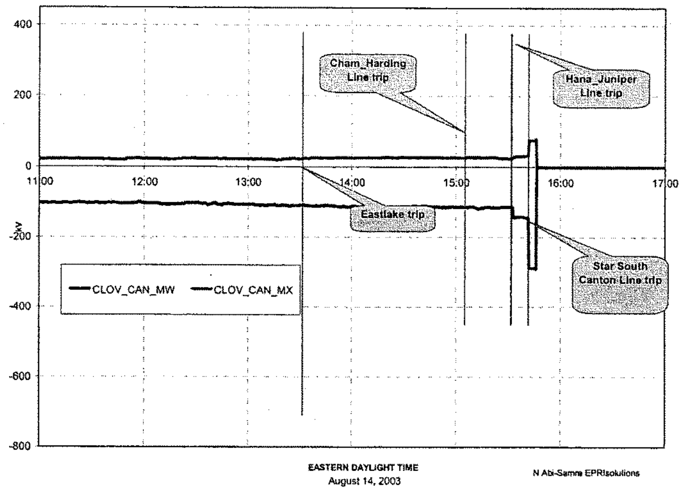

Figure 8 – MW and MVAR flows on Cloverdale-Canton Central 138 kV line

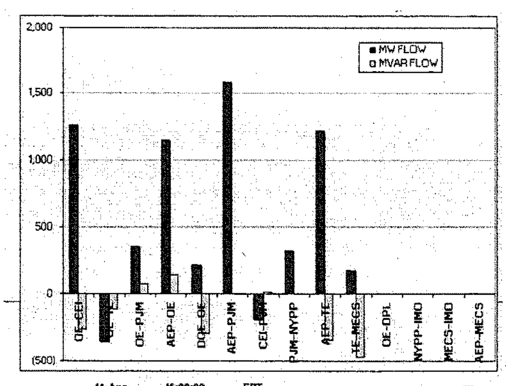

Figure 9 – Actual Flows (MW and MVAR) in the Affected Areas at 16:00
Total FE MVARs = 117 Net Export

At 15:00, voltages in FirstEnergy's system continued to decline. When Harding to Chamberlain tripped, the Star voltage declined by about 1% to 97.3% of nominal. When

Hanna-Juniper tripped, the Star voltage declined by another 2.6% to 94.7% of nominal. When Canton Central to Tidd tripped, the Star voltage declined by an additional 4.4% to 90.3% of nominal. Each successive line trip caused the additional voltage drop to become more pronounced. This is an indication of severe voltage degradation. Voltage at the Cloverdale-Canton Central was 94.9% prior to its trip, according to MISO EMS data.

From about 2:35 PM to about 3:30 PM, the alarm system of the FirstEnergy system appeared not to be performing as designed. As a consequence, the FirstEnergy operators may have lacked timely information to assess the developing conditions. During the day, other control areas also reported performance problems with some of their hardware and software, as indicated in the MISO phone transcripts.

Between 16:00 and 16:30 EDT

- 16:06:03 – Sammis-Star 345 kV tripped
- 16:08:58 – Galion-Ohio Central-Muskingum 345 kV
- 16:09:06 – East Lima-Fostoria Central 345 kV
- 16:09 to 16:30 – Numerous line and generator trippings followed resulting in wide-spread customer interruptions

Immediately after Sammis-Star tripped, voltages in the FirstEnergy area declined severely. The subsequent disturbances happened so rapidly that human intervention was in general not possible.

Preliminary Incremental MW Load Flow Analysis

To understand why heavier flows from south to north were observed on August 14, 2003, the EPRI team performed a quick and preliminary load flow study using a load flow case developed by Commonwealth Associates, Inc. (CAI)[8] The load flow conditions were reconstructed using publicly available information and educated assumptions of system conditions on August 14, 2003, preceding the series of outages.

The EPRI study used an incremental approach on top of the CAI base case and was based on the following assumptions.

Study Assumptions

- The EPRI team performed an incremental analysis of the changes in line flows due to the addition of 2610 MW of merchant plant output in SE Ohio. This information was not known by CAI and was therefore not modeled in the CAI data. Due to limitation of time, we did not model the approximately 230 MW at Wheatland, Indiana. (Modeling this in subsequent studies would be important for comprehensive understanding of the regional voltage and reactive margins and their effect on adjacent areas.)

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[8] Commonwealth Associates, Inc. (CAI), "White Paper – A Scenario Describing the August 14, 2003 Blackout", 9/9/2003.

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- We focused only on the MW flows. The CAI data did not model the reactive capabilities available on August 14, and the simulated MVAR flows did not match well with the measured MVAR line flows in the FirstEnergy areas.
- We selected certain lines to monitor in the FE and AEP areas.
- We used the NERC TagNet data to reconstruct the distribution of the sinks for the transactions with the sources at the three merchant plants in SE Ohio. The results of that analysis provide the basis for the assumed sources and sinks for this incremental load flow case, as shown in the following Table 2.

Table 2 – Assumed Sources and Sinks for the Incremental Load Flow Study[9].

	EPRI Base Case	Change Case	Source(+ve) / Sink(-ve)
DEWO Net Export (MW)	-	610	610
Waterford + DELO (MW)	-	2,000	2,000
IMO Net Export (MW)	(1,600)	(2,200)	(600)
CIN Net Export (MW)	287	237	(50)
MECS Net Export (MW)	422	172	(250)
CE Net Export (MW)	1,445	1,365	(80)
FE Net Export (MW)	(3,613)	(3,763)	(150)
Assumed AEP Purchase	-	1,201	(1,201)
System Losses (MW)	14,667	14,946	(279)
Total			0

The results of the incremental load flow study are highly dependent on the assumptions in Table 2, especially where the sinks were located and where the re-dispatched generators in the AEP system were located, in order to absorb the incremental generation from the IPPs. As is done routinely in such wide-area transfer studies, the area swing generator in each importing control area will be automatically used by the load flow program for reducing generation output to achieve a desired interchange schedule. In the AEP system, however, the area swing generator was Sporn, which was located close to those merchant plants. We allowed Sporn to be used as the swing bus, even though in reality, the actual generators re-dispatched to absorb the purchases would likely be the most expensive units on line at that time. As we did not have such data about the actual generation dispatches in AEP, we used Sporn as the swing bus, even though that might underestimate the incremental flows across the AEP grid.

Also, because the Eastern Interconnection at heavy load conditions is highly congested, load flows often run into convergence problems when large changes are made to the desired interchange schedules. As a result, the incremental results were obtained by breaking up the changes into six cases. Along the way, it was noted that Sporn was generating a significant negative MW value (-1357 MW) and reached its MVAR limit, and the load flow could not converge in the study. To make it converge, we backed off manually by 700 MW the Kammer generation, which is close to the Muskingum River station near the Waterford and the Washington plants. That is to say, we did not back off AEP generation in the western part of its system to influence the incremental flows.

[9] NERC TagNet data are generally reported as inter-control area schedules. They exclude schedules from other sources inside a control area with sinks designated to be also inside that control area.

One assumption that would influence the results was that Ontario (IMO) was importing 600 MW more than the amount in the base case. This is an assumption based on the fact that IMO was importing more power on August 14 than was typical, and that it was increasing its import continuously between 12 PM and 3 PM that day. Therefore, it is conceivable that some inadvertent interchanges during that period might have found IMO to be their sink. Another possibility is that some control areas might have wheeled more power to IMO at that time. Again, with more actual dispatch and interchange schedule data available from all control areas, the study can be refined.

Incremental Load Flow Results

The results of the incremental load flow study are summarized in Figure 10 below.

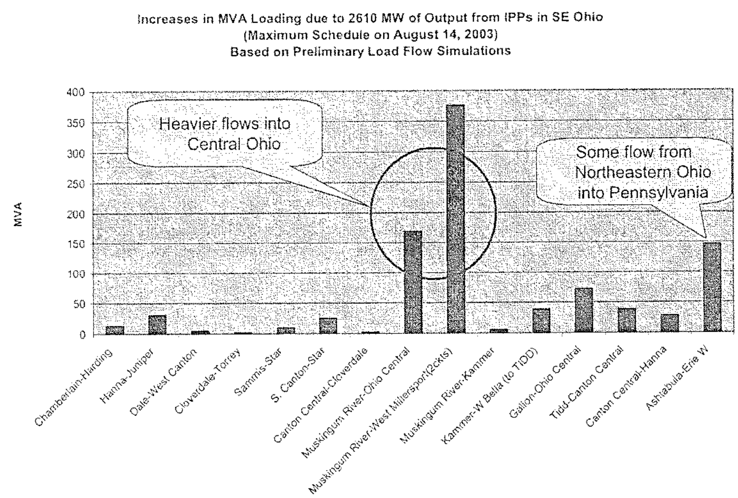

Figure 10 – Estimated Increases in the MVA Loadings of Selected Transmission Lines in FirstEnergy and AEP Due to 2610 MW of Output from IPPs in SE Ohio (Maximum Schedule) on August 14, 2003
(The simulated line flows on these lines carried very low MVARs. Thus the MW loadings on these lines were approximately equal to the MVA loadings.)

From the assumptions about the sinks of the scheduled generation, about 1480 MW of the IPP output was absorbed by AEP or went towards increased system losses. Thus AEP exported about 1130 MW. Figure 10 shows that of this 1130 MW, about 540 MW (170 plus 370) flows on two transmission paths into central Ohio from Muskingum River. Also, about 140 MW flows from Ashtabula to Erie West, which is in the direction to the Northeast.

Significantly, numerous assumptions and inherent modeling inaccuracies were necessarily adopted for this preliminary power flow analysis. There is a need for additional detailed data to accurately assess the system conditions and sequence of events, including specific generator dispatches, reactive outputs and capabilities, status of other reactive devices and control settings, transformer tap settings, phase shifter settings, capacitor banks, SVCs, HVDC converters, scheduled and actual transactions, etc. Since reactive conditions and power transfers appear significant in the analysis, a concerted effort by all affected entities is required to benchmark refined models against actual system measured data to validate the study results.

The normal MVA rating of the Muskingum River to Ohio Central line is 938 MVA in the CAI data, which was based on the NERC MMWG (Multiregional Modeling Working Group) case for the summer of 2003. Therefore, the 170 MW of incremental flow on the Muskingum River line amounts to about an 18% increase in the loading of the line. In the CAI base case, that line was already loaded to about 94% of normal rating. With the change case, the line loading went to 112% of normal rating. Without more data and more computer studies, the overload on that line or other lines in the AEP system during August 14, 2003 cannot be confirmed. However, this is a hypothesis that deserves further investigation.

In summary, the incremental load flow study shows that if the actual generation outputs of the merchant plants in SE Ohio on August 14, 2003 corresponded to the schedules obtained from the NERC TagNet data, they may have increased the flow through Central Ohio towards Northern Ohio and Michigan. Part of the flow, though to a lesser amount, would have gone along Lake Erie towards the Northeast. If Ontario was importing more power at that time, part of that generation may have ended in Ontario, mostly via Michigan and partly via New York.

In short, this incremental study indicates that this hypothesis is an area that deserves further data collection and analysis.

Was August 14, 2003 Typical and Were the Series of Disturbances Related?

In an attempt to answer the question whether August 14, 2003 was in someway special or different, we looked at data available from TagNet for all hours and all days from August 1 to August 14. We computed the net exports for most of the control areas in the northeast. We plotted the 24-hour weekday profiles of their net exports and computed the average weekday profile from Aug 1 to Aug 13. We plotted each of the weekdays and the average profile. From these graphs, we found that August 14 was distinct from the early August weekdays for AEP, MECS (Michigan Electric Coordinating System), FE and IMO (Independent Market Operator of Ontario). For some of them, August 13 was similar to August 14. To illustrate, the graphs for AEP and IMO are shown in Figures 11 and 12.

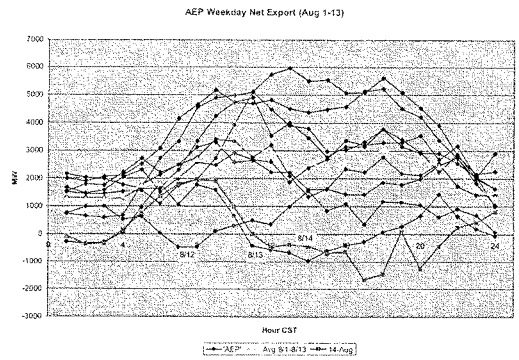

Figure 11 – AEP Weekday Net Export Schedules (Aug 1-13, 2003)

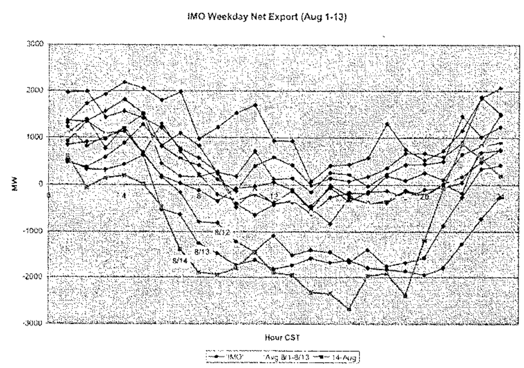

Figure 12 – Ontario Weekday Net Export Schedules (Aug 1-13, 2003)

The data obtained from TagNet about the schedules of the SE Ohio merchant plants seem to be consistent with the reduced net exports out of AEP's own generation on August 12, 13 and 14. The higher imports by Ontario on these same three days seem to be consistent with the increasing hot temperatures on those days. Both sets of curves appear to lend some possibility to the incremental load flow studies associated with the operation of the IPPs in SE Ohio.

While August 13 and 14 were similar, insights as to why the disturbances happened on August 14 and not on August 13 can perhaps be found in the voltage behavior on those two days, which may be different. To help shed light on the voltage behavior, we obtained hourly voltage profiles from August 8 to August 14, 2003 for the Star 345 kV bus in the FirstEnergy area. Integrated data for August 14, hour 15 was unreliable due to disturbances, so subsequent data are also not included. This is plotted in Figure 13 and 14.

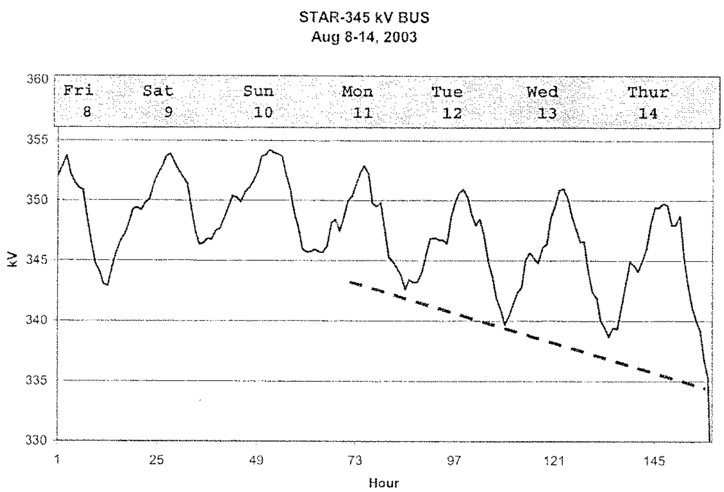

Figure 13 – Star 345 kV Bus Voltages (Aug 8-14, 2003)
Lowest normal operating range = 327.8 kV (95% of 345kV)

Figure 13 clearly shows a trend in the system voltage that was not only noticeable voltage degradation during each day, but also a noticeable worsening of the voltage problem in the three successive days preceding August 14, 2003. Additional data for other days preceding August 8 would be useful to validate this observation that August 14 was atypical. Based on this data alone, however, it supports the need to investigate the causes of the successive voltage degradation in the three days preceding the outage.

Figure 14 narrows the analysis into the hours preceding the major disturbances at about 4 PM on August 14, 2003 and compares the voltages during those hours in the preceding weekdays. The curves show that August 12, 13, and 14 were clustered together as compared to August 8 and 11. Again, the successive worsening of the voltage profiles in those three days is quite apparent. It can further be observed that on August 12, the voltage reversed its downward trend and began to increase at about 13:00 EDT. On August 13, the voltage continued to drop for another hour before increasing at 14:00 EDT. On August 14, the voltage dropped at a faster and faster rate starting at 12:00 and did not show any sign of reversing its downward trend, in contrast to prior days. Higher afternoon temperatures, greater and increasing power requirements in the Eastern Interconnection and the status of generating units could have contributed to lowering the

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overall reactive reserve margin on August 14. Perhaps the loss of three generators on August 14 contributed to lowering the overall reactive reserve margin on that day.

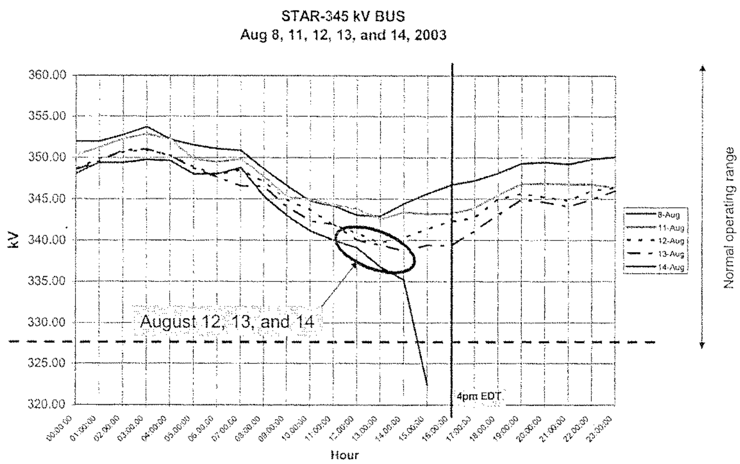


Figure 14 – Star 345 kV Bus Weekday Voltages (Aug 8, 11, 12, 13 and 14, 2003)

Another factor that was documented by the MISO operator phone transcripts and described in the timeline at 13:30 was the possibility that merchant plants are not all designed to provide sufficient reactive power output. The Wheatland plant had four 125 MW simple cycle gas turbines and was rated at 508 MW[10]. Thus when 2 units were online shortly after 14:00, its maximum rating would be 254 MVA. It was scheduled to output 236 MW, and apparently the MISO operator had reason to believe that it was capable of only 60 MVARs. In terms of capacity factor, it was operating at 236/254 = 93%. If indeed it was generating 60 MVARs, its power factor at the time would be about 97%. Either calculation would support the MISO operator's concern about voltage support. Similar calculations place the Hanging Rock plant (1240 MW capacity)[11] running at 1200/1240 = 97% capacity factor from 13:00 on. Likewise, the Washington[12] and Waterford[13] plants were scheduled to output at 15:00 EDT 611 MW and 800 MW, respectively. Compared to their plant ratings of 620 and 850 MW, they were running at 98% and 94% capacity factors, respectively. Furthermore, in order to absorb 2600 MW of merchant plant output from SE Ohio, even with the incremental losses estimated to be about 280 MW, about 2320 MW of other power plants would have to be reduced in

[10] http://www.alleghenyenergysupply.com/generating/default.asp
[11] http://www.duke-energy.com/businesses/plants/own/us/midwest/hangingrock.asp
[12] http://www.duke-energy.com/businesses/plants/own/us/midwest/washington.asp
[13] http://www.pseg.com/media_center/pressreleases/articles/press_2003-08-11.html

output or shut down. If part of this was achieved by shutting down some units, then some reactive support would be lost from the Eastern Interconnection. While there is no data available to the EPRI team on how much reactive power was put out by other power plants in that area to compensate for the lack of reactive power output from the merchant plants, it certainly raised the question whether it was sufficient to maintain voltages for the immediate area and not create a burden on adjacent areas. Thus, while no definitive conclusion can be made at this time, this is certainly an area deserving further investigation.

Changing Patterns of Power Flow and Frequency Behavior

When an interconnected power grid is heavily congested, as is the case with the Eastern Interconnection, incremental flows are significant contributing factors to the total loading of critical transmission bottlenecks. This preliminary study illustrates the importance of simulating different wholesale power transfer patterns in the Eastern Interconnection. It is well known among transmission planners in the Eastern Interconnection that the wholesale power transfer patterns have changed to a significant degree since restructuring and the FERC Order 888 in 1998. New bottlenecks have emerged as transfer patterns change. New power plants, their real and reactive ratings, and their locations also have a major effect on the wholesale power transfer patterns.

With increasing number of wholesale power transactions starting and ending at the same hours due to common business practices, the Eastern Interconnection has experienced larger fluctuations of system frequency, especially during morning load pickups, afternoon drop offs and at about 10 PM or 11 PM at night when many transactions end at the same time. Unanticipated frequency excursions that occur regularly due to inadvertent interchanges may degrade the region's ability as a whole to balance generation and load in response to sudden disturbances. This is another systemic problem that deserves further consideration.

Studies done under the new wholesale market environment should be reviewed regularly to determine if their conclusions are still valid. The study approach and the study tools should also be re-examined, in light of the need to consider a large number of simultaneous transfer patterns. For example, the approach taken by the NERC Pre-Season Assessment Study Team (PSAST) supported by EPRI's Transmission Reliability Initiative for assessing the reliability of the Eastern Interconnection for the summer of 2002[14] made use of a combination of a simultaneous transfer capacity program, TRACE, and a new software called the Community Activity Room (CAR). The CAR is also being tested by EPRI and TVA as an online congestion monitoring tool.

Rapid Online Assessment of Transmission Bottlenecks

In addition to the greater need to update planning studies, the rapidly changing transfer patterns within a day would seem to call for more rapid online studies of transmission bottlenecks over the entire Eastern Interconnection. In such online studies, the actual line

[14] "Summary Report: Summer 2002 Eastern Interconnection Pre-Season Study and New Tools for Community Activity Room", EPRI Report, July, 2002.

outage status of all critical transmission lines must be modeled as they take place. Topology Estimator, which is a super State Estimator program capable of detecting the correct network topology of a wide area such as an Interconnection, is a technology that has recently become available. It appears that a Virtual RTO[15] concept proposed for integrating the communication and computing infrastructures of the physical RTOs or ISOs of an Interconnection would be a potential platform to implement an Interconnection-wide Topology and State Estimator.

It is also vital that all the operators in an interconnection see the same bird's-eye view of the entire interconnection when it comes to managing congestion. Using geographically-based transmission flow displays driven by the same real-time data will help. Also, the Community Activity Room offers a radar-screen-like visual display of congestion in any major bottlenecks in the entire Interconnection, either in 3D or 2D. With such display tools, all the RTOs and grid operators in the same interconnection can coordinate effectively to relieve congestion that requires wide-area coordinated measures. When long distance and wide-area wholesale power transactions are significantly impacting congestion, local measures are ineffective. Such wide-area display systems will enable grid operators to handle situations before they develop into emergencies. Upgrading data collection capability and analytic tools with systems that are now available or under development is likely a necessary requirement to assuring grid control and stability under the current pervasive conditions.

Reactive Reserve Margins

Another area deserving further investigation is the reactive reserve margins in all parts of the Eastern Interconnection. Little is known about the actual amount of dynamic and static reactive capacities online at any given time in various parts of the grid. Since restructuring and open access, power plants that are not directly controlled by grid operators do not typically have enough financial incentives or contractual obligation to generate reactive power. Without sufficient reactive sources at the generating end of the high voltage grid, voltage support in a wide area cannot be achieved effectively. In addition to not supporting grid voltage, generators that operate at close to unity power factors in some situations may consume reactive power from the grid, either directly or through the reactive line losses from the increased line flows from their plant outputs.

Therefore, to ensure grid reliability, voltage support is now an important and critical concern of the grid operators. It is clear that grid operators do not have an accurate real-time picture of the reactive reserve margins in their own service areas, due to the lack of data about the merchant plants.

There are many ways deficiencies in reactive power can develop in a system that seemingly had adequate resources. A power system may be able to progress through one day's heavy load periods with little or no low voltage problems. This same system, however, can experience low voltages if it had major contingencies of generators or transmission lines, heavy power transfers through its systems, or customers within the

[15] Stephen Lee, "Executive Summary of Virtual Regional Transmission Organizations And the Standard Market Design", EPRI Report, Product ID 1007680, February 5, 2003.

system operate their equipment differently. The greater the level of power transferred through the system, the greater the reactive power losses and voltage drops will be. Conversely, reactive power losses are directly related to system voltage levels. The lower the voltages, the heavier the reactive losses are. If the active power transfer on the system is high, even small increases in MW transfer could lead to large increases in MVAR usage. Figure 15 illustrates this concept.

In this textbook example, two 200 mile, 345 kV lines are carrying equal load (about 470 MW, and 30 MVAR). Their initial operating point is labeled in the Figure 15 as "Two Lines In". When one line trips, the remaining line would carry the total load (assuming the radial configuration shown). The new operating point is labeled as "1 Line In". As can be seen from this figure, the MWs on the remaining line would double, but the MVAR would dramatically increase to about 1100 MVAR. This sudden increase in reactive losses potentially escalates reactive demand on the system, reduces reactive reserves, and increases the risk of a gradual voltage collapse. Furthermore, the increased reactive losses results in a higher line current for the same amount of MW flow, thus loading this textbook line beyond its thermal rating. The line under such conditions would sag, hence increasing the chances of contacting trees. The additional MVAR would have to come from the system, which would increase the flows on other lines, further increasing reactive losses, assuming that the system has enough margin to support the increased VAR demand. This phenomenon could lead to increased depletion of reactive reserves on the system, potential voltage degradation under increasing system stress, and possibly resulting in voltage collapse and line and unit trippings.

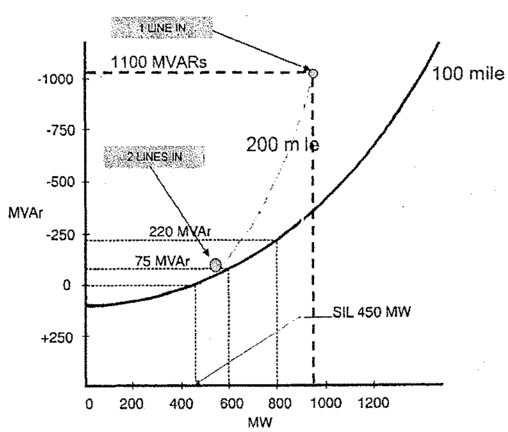


Figure 15 – How Losing A Parallel Line Would Compound the Overload Problem When MVAR Flow is Heavy

EPRI

While Figure 15 is an example from a textbook, Figure 16 is for the loading of a 138 kV line in the FirstEnergy System. Notice the similarities in the phenomena.

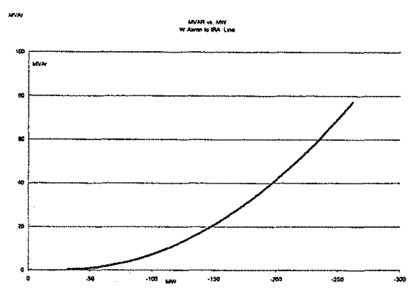


Figure 16 – MVAR load increase in the West Akron to Ira line

Figure 17 shows the MVAR flows on four transmission lines at the West Akron substation in FirstEnergy following the tripping of adjacent lines. Not all the lines from the West Akron substation are shown for clarity. The graph shows that as one line trips, adjacent lines pick up both MW and MVAR flows, and MVAR flows increase more than MW flows.

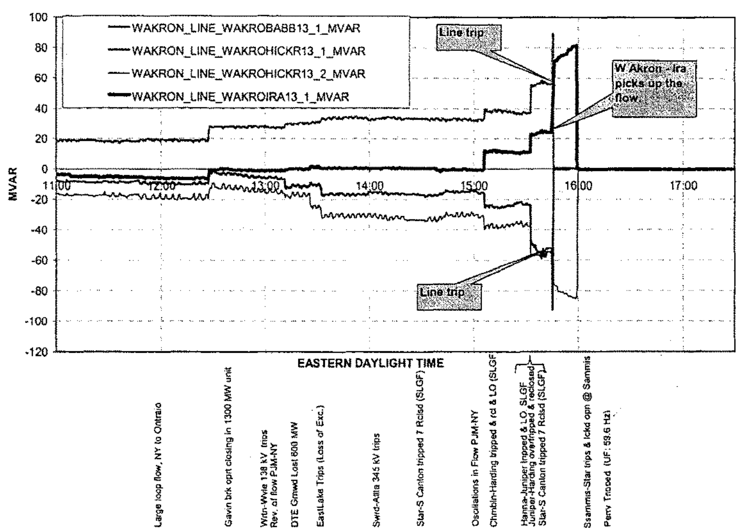


Figure 17 – MVAR Flows in Adjacent Lines Following Line Trips

Wide-Area Voltage Problems

Voltage problems can spread to adjacent areas because an area which is deficient in reactive power will draw on neighboring systems for reactive support, thus dragging down the voltages of the adjacent systems.

A good analogy to use for understanding reactive power and voltage support is that of a tent made of heavy canvas. The tent covers a wide-area grid. The level of the tent at various parts of its canvas represents the voltage level. In order to prevent the sagging of the canvas from causing it to touch the ground, one can visualize a set of powerful water jets spaced out underneath the canvas. The forceful water jets support the tent at the points where they impact the canvas. The weight of the tent is then delicately balanced by the water jets. If one then places heavy objects on the canvas to represent reactive loads on the grid, in order to carry these additional weights, one must increase the outputs of the water jets at the most effective locations underneath the tent. Without these additional forces from underneath to support the tent, the additional weight will cause the canvas to sag and sag and eventually the whole tent will collapse.

Another insight from this analogy is the reactive power flows, or MVARs. Reactive power flows from high voltage to low voltage. When a water jet pushes that part of the tent above the adjacent parts, reactive power will flow from where the tent is higher to where it is lower. In doing so, it helps support the adjacent parts. Therefore, in a situation where the voltage in an area is low, if the reactive power flows from that area to the adjacent areas, this would be an indication that the canvas in the adjacent areas is even lower. This was shown in Figures 5, 7, and 9 for 1 PM, 2 PM, and 4 PM, with FirstEnergy being a net exporter of reactive power to its neighbors in the amounts of 286, 340, and 117 MVARs, respectively. A natural question to ask is "how much of the sagging in the FirstEnergy area is caused by the lack of water pressure in the water jets in that area or the dragging down by the adjacent areas because of the lack of water jet pressures in those other areas?"

Areas for Further Investigation

In summary, this white paper has presented data and some preliminary study results to suggest that the events of August 14 were not independent random coincidences. Two potential contributing factors to the power outages were long distance wholesale power transfers and wide-area voltage behavior. They combined to create the operating environment in which even small disturbances, when added together, contributed to the widespread disturbances. To explore this hypothesis further, additional data for the real (MW) and reactive (MVAR) capacities and the real and reactive loads in all parts of the Eastern Interconnection during August 14, 2003 are required so that an overall interconnection-wide load flow and voltage study can be done.

In the course of this study, EPRI did not have sufficient time or resources to draw definitive conclusions or make final recommendations to transmission providers, grid operators, and ISOs/RTOs directly impacted by the outage or to the industry at large. However, based on the results of analysis and the knowledge and experience of the EPRI team, areas for further investigation have emerged. The EPRI team has provided two lists of areas for further investigation. The first list is specifically for transmission providers, grid operators, and ISOs/RTOs directly impacted by the outage. The second list is for the broader industry at large. These are listed below, not necessarily according to any priority order.

Areas for further investigation for transmission providers, grid operators, and ISOs/RTOs directly impacted by the outage:

1. Investigate the need for reactive support.
2. Investigate any unexplained transmission line tripping.
3. Review emergency ratings of transmission lines and safe operating limits, including voltage and stability limits and consider monitoring of real-time dynamic line limits.
4. Review line relay malfunction and settings under different flow patterns.
5. Investigate alarm system, data communication, Internet access, and Energy Management System hardware and software performance on August 14, 2003 so that improvements can be made to prevent malfunctions from affecting the response of grid operators to future disturbances.
6. Review system operation procedures, emergency action response instructions, real-time information sharing and communication protocols among operators, MISO operators, and adjacent systems' operators.
7. Review under frequency and under voltage load shedding and system separation schemes.
8. In parallel and in coordination with the studies done by NERC or the U.S./Canada Power Outage Task Force, model the individual entity system response in the Eastern Interconnection, in particular paying close attention to modeling wide-area and long distance wholesale power transfer patterns including the operation of independent merchant power plants.
9. In parallel and in coordination with the studies done by NERC or the U.S./Canada Power Outage Task Force, simulate similar conditions and determine required responses to avoid future disruptions, including a comprehensive contingency analysis and probabilistic reliability assessment.

Industry Recommendations:

1. Collect and review additional data from all sources in order to study the wide-area and evolving situations on August 14, 2003. In particular, data about merchant plant scheduling and operation, reactive capacities and reactive reserve margins in the entire Eastern Interconnection, are extremely important to performing a complete analysis of the contributing factors to the power outage. The problem does not appear to be an isolated incident of unlikely random failures. Potential systemic problems associated with communication and coordination among the reliability entities, generators, marketers and transmission providers should be assessed.
2. Review the current methods for scheduling power across the Eastern Interconnection to ensure that all simultaneous transfer limits are recognized, and model system response in the Eastern Interconnection, in particular paying close attention to

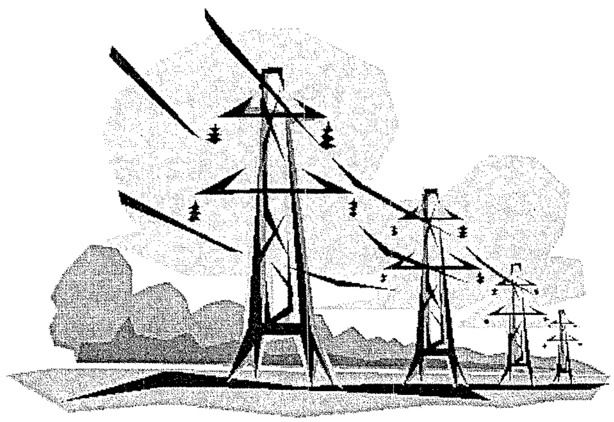
modeling wide-area and long distance wholesale power transfer patterns including the operation of independent merchant power plants.

3. Review the adequacy, applicability, and utilization of wide area electronic exchange of operating data to address potential improvements.
4. Investigate the need for reactive support in specific areas or in the Eastern Interconnection as a whole using computer studies.
5. Simulate similar conditions and determine required responses to avoid future disruptions, including a comprehensive contingency analysis and probabilistic reliability assessment.
6. Review under frequency and under voltage load shedding and system separation schemes.
7. Investigate alarm system, data communication, IDC and Energy Management System hardware and software performances on August 14, 2003 in all the control areas affected by the disturbances so that improvements can be made to prevent any such malfunctions from affecting the response of grid operators to future disturbances.
8. Investigate all transmission line trippings to determine potential improvements.
9. Review emergency ratings of transmission lines, and safe operating limits, including voltage and stability limits and consider monitoring of real-time dynamic line limits.
10. Review line relay malfunction and settings under different flow patterns.
11. Review system operation procedures, emergency action response instructions, real-time information sharing and communication protocols among grid operators and between ISOs or RTOs.
12. Review the relevance and adequacy of NERC's planning and operating guidelines.
13. Review protection schemes of power plants (including merchant plants) and their coordination with the protection of the interconnected grid.
14. Review the adequacy of transmission impact studies conducted by an RTO or a transmission provider to connect a new power plant to the grid, especially in view of the needs to include complex dynamics and voltage stability that are sensitive to changing transfer patterns, and review the adequacy of NERC standards related to reactive capability, voltage support, and other ancillary capabilities by all power plants, including merchant plants.
15. Review data archiving requirements and accessibility. A major difficulty for post-disturbance analyses is the lack of availability of adequate historical data related to critical infrastructure elements. An industry standard for the required data (e.g., voltages, flows, generation and loads, reactive support device status, etc.), common formats and archiving requirements for different classes of data appear to be needed.

Michigan Public Service Commission

Report on August 14th Blackout

November 2003



Public Service Commission
J. Peter Lark, Chair
Robert B. Nelson, Commissioner
Laura Chappelle, Commissioner

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MICHIGAN PUBLIC SERVICE COMMISSION

REPORT

BLACKOUT OF AUGUST 14, 2003

EXECUTIVE SUMMARY

The August 14, 2003 blackout was a wake-up call concerning reliability of our nation's electric grid. What started out as a typical warm summer day, which looked largely uneventful to most electric reliability coordinators (and others) in the northeastern region of the country took a sharp u-turn at approximately 4:10 p.m., when, in a matter of seconds, 50 million North Americans found themselves without power. North America's largest ever outage stretched from southeastern Michigan through Ontario and northern Ohio, all the way east to New York City. Through this event, North Americans were abruptly reminded how vital electricity is in our everyday lives and how tightly interconnected and vulnerable this country's electric grid has become.

The Public Service Commission did not attempt to determine the root cause of the blackout. However, our investigation did not reveal any evidence that Michigan utilities or transmission operators were responsible for the blackout. All of the transmission line and power plant outages that occurred in the two and one-half hours preceding the power surges that precipitated the blackout involved the facilities of FirstEnergy and American Electric Power in Ohio. These events led to two large power surges as power from southern Ohio attempted to reach load in northern Ohio. The first surge was from southern Ohio, west to Indiana, north to western Michigan, east to the Detroit area, and south to northern Ohio. This surge resulted in the opening of interconnections in central Michigan between the western part of the State and the Detroit area. These interconnection trips occurred as designed to prevent damage to equipment from the power surge. The second power surge involved a giant loop from southern Ohio to Pennsylvania to New York to Ontario to Michigan to northern Ohio. This surge resulted in the blackout around what is generally referred to as the Lake Erie Loop.

Michigan utilities and transmission companies were not notified of the problems being experienced by FirstEnergy and American Electric Power and received no advance warning of the potential blackout. The first indication in Michigan of an impending emergency occurred at 4:09:27 p.m. when an interconnection in central Michigan exceeded its emergency rating as a result of the first power surge coursing through the State. A minute later the power outages began and by 4:15 p.m., the blackout was complete. A total of 2.3 million customers of The Detroit Edison Company, Consumers Energy Company, and the Lansing Board of Water and Light were left without power.

Our investigation leads to the conclusion that electric reliability has been seriously compromised by the fragmented and ineffective regulation of the electric transmission system. The Midwest market is coordinated through two regional transmission organizations (RTO), rather than one. Moreover, the two RTOs are voluntary organizations that do not cover contiguous territories but rather are intermixed in a checkerboard fashion. This "Swiss-cheese" approach to coordination prevents any one entity from comprehending the overall situation. The situation is exacerbated by a lack of enforceable reliability standards. The North American Electric Reliability Council (NERC) is responsible for the development of procedures for reliability coordinators, but lacks the authority to enforce those standards. A NERC investigation of compliance in 2002 found that there were 444 violations of operating measures totaling $9 million in "simulated sanctions". In addition, the Federal Energy Regulatory Commission (FERC), the agency responsible for economic regulation of transmission, indicates that it lacks authority to develop or enforce reliability standards.

In our opinion, the simulated enforcement of reliability standards is inadequate to protect Michigan or the nation's citizens. We recommend that the FERC be authorized to require membership in a single transmission organization for each region and have the jurisdiction to mandate the development of reliability standards and enforce those standards with real rather than simulated sanctions.

With regard to recovery from the blackout, our investigation reveals that Detroit Edison, Consumers Energy, and the Lansing Board of Water and Light performed appropriately. However, we conclude that there were two factors that caused restoration in Michigan to lag behind other States. First, Detroit Edison's computerized dispatch system was inoperable due to the blackout, which required additional time and effort for the restoration. We recommend that the utility conduct a study of potential modifications to the system and report to the Commission on the results. Second, the failure of rupture disks at four of the Detroit Edison generating plants slowed the pace of restoration. Since rupture disks are a feature designed to protect against more serious damage to the units, this does not necessarily indicate a problem. However, we are recommending that Detroit Edison analyze the operation of the rupture disks on its units, including a comparison with the operation of disks on other utility systems affected by the blackout, to determine whether any changes are warranted.

Finally, with respect to emergency planning and response efforts, we conclude that the operations conducted through the State Emergency Operations Center (SEOC) were effective in implementing the emergency response plans. However, we note two important improvements that can be made to better prepare for future contingencies. First, the Commission Staff members who participated at the SEOC were volunteers. We conclude that Staff for the SEOC should be assigned in advance and receive training in the operations required to implement the emergency plans. Second, we note that the existing emergency electrical procedures were adopted in 1979 and have not been reviewed since. Although those particular procedures were not needed in this instance, we conclude that it is time for them to be reviewed and, if necessary, updated.

INTRODUCTION

The August 14, 2003 electricity blackout stamped an indelible impression on the minds of North Americans. Stretching from as far west as Detroit, the blackout covered much of Ontario, Canada, northern Ohio and extended all the way east to New York City. Almost as quickly as the event struck an avalanche of worldwide media coverage reported that the largest electric blackout in North American history had, in a matter of minutes, suddenly plunged 50 million North Americans into darkness and forced thousands of businesses to abruptly close operations. In its wake a renewed appreciation of the importance of electricity in all aspects of our everyday lives was stirred along with a rekindled understanding of just how intricately interwoven, interdependent, and vulnerable our electrical system has become. A search for answers as to what happened on August 14, and, more importantly, what can be done to strengthen the reliability of our electric system to prevent such an event from recurring in the future was immediately set in motion with a sense of keen urgency. With over six million residents out of power for up to two days and hundreds of businesses shut down, some for several days, Michigan elected to commence an investigation to examine the blackout from our vantage point.

The Michigan Public Service Commission is one of a number of entities commencing an investigation to examine what went wrong on August 14 and, more importantly, to determine how such an event can be prevented from recurring in the future. The recommendations in this report are based upon an analysis of those events in and around the State that resulted in the blackout. The report is organized into five parts. Part I – Facts and Overview – presents a summary of the electric power system, the relevant actors in that system, and the timeline of events on and after August 14. Part II – Electric Transmission – analyzes the operation of the transmission system, including operators and regional oversight organizations. Part III – Utility Operations – analyzes the operation of utility distribution systems and the efforts of utility personnel to recover from the blackout. Part IV – Emergency Planning and Response – discusses the response of the Michigan Public Service Commission and other State government agencies in the recovery operations and discusses the interdependencies among the various infrastructures that were affected by the blackout. Finally, Part V – Conclusions – presents a summary of the recommendations put forth in the report.

This report was prepared by the Michigan Public Service Commission and its Staff. The Commission wishes to thank Gary Kitts, Lisa Molner, Jeff Pillon, and Paul Proudfoot, who were the primary investigators, along with Robin Barfoot, Bill Bokram, Tim Boyd, Angela Butcher, Bill Celio, Mike Fielek, Mick Hiser, John King, Steve Paytash, and Linda Stevens. Information was obtained from various entities involved in the power production and delivery system, including utilities, transmission companies, and regional transmission organizations. Information was also provided by other State government agencies – the Commission wishes to acknowledge the assistance of Bob Tarrent and Celeste Bennett of the Department of Agriculture; James Cleland, Water Division, Department of Environmental Quality; Captain Dan Smith, Michigan State Police; Eileen Phifer, Department of Transportation; Dan Lohrman, Department of Information Technology; and Colonel Mike McDaniel, Homeland Security Advisor to the Governor.

The events of August 14 are reminiscent of a scene from the 1950 movie The Day the Earth Stood Still. Professor Barnhard was talking to his secretary Hilda about the worldwide electric blackout that had been caused by alien visitors to Earth. He asked her, "Does this make you feel insecure?" and she said "Yes." His response was "I am glad," because he hoped that the blackout would bring about change. The Commission does not wish to suggest that anyone should be glad about the events of August 14, but we believe that the recommendations in this report will, if implemented, bring about the changes necessary to ensure a more reliable electric system for all.

PART I

FACTS AND OVERVIEW

Section 1.1: Overview of the Electric Power System

We have come to expect it – flip the switch and the light comes on. It is something that almost every child, from the age of two, learns as the natural order of things. However, this everyday commonplace would have seemed like magic to those predating the work of Thomas Alva Edison. Indeed, a large, complex system of organizations and infrastructure is required for the lights to stay on.

Generally, the electric power system is divided into three components: generation, transmission, and distribution.

Generation, or the act of producing electricity, is, for the most part, carried out at large power plants, which convert another energy source to electricity. Although the specific details vary, in general, fossil fuel plants burn coal, oil, or natural gas, use the resulting heat to convert water to steam, and then run the steam (or the heated air from combustion) through turbines to create electricity. Other fuels, such as landfill gas or municipal solid waste, can be substituted in essentially the same process. The generating process in nuclear plants is similar, except that the heat is derived from the fission decay of radioactive elements.

Electricity can also be generated by non-thermal means. Hydroelectric plants generate electricity by directing falling water through turbines. Electricity can also be produced using wind-driven impellers to turn the generating unit. In addition, sunlight can be used to generate electricity in photovoltaic cells. Based on data (through June 2003) published by the Energy Information Administration, the current mix of electric generation in Michigan and nationally is as follows:

Fuel Type	Michigan	United States
Coal	62.6 %	51.0 %
Nuclear	23.3 %	20.1 %
Natural Gas	10.2 %	17.2 %
Renewable Power[1]	2.5 %	2.1 %
Petroleum	0.8 %	2.8 %
Hydro	0.6 %	6.8 %

The transmission function involves the large-scale movement of power from generating units to the distribution networks, which then deliver that power to the customer. Transmission is distinguished from distribution in that transmission lines are larger, operate at significantly higher voltages, and individually deliver much larger amounts of power. Transmission can be

[1] The Energy Information Administration definition includes: wood, black liquor, municipal solid waste, landfill gas, sludge waste, tires, agricultural byproducts, biomass, geothermal, solar thermal, photovoltaic, and wind.

fairly described as the bulk transport of power primarily at wholesale, while distribution is the delivery to the customer of smaller amounts of power at retail.

In the past (and still to a great extent today), all three functions were performed by a single entity. Investor-owned utilities are usually large private companies that generate their own power and serve customers in designated franchised service territories. In Michigan, there are two large investor-owned utilities (Detroit Edison and Consumers Energy) that between them serve more than 80% of the State and seven smaller ones.[2] Cooperative utilities are member-owned companies that normally serve rural areas. There are 12 cooperative utilities in Michigan. Municipal utilities are publicly-owned organizations that serve the local municipality and may serve some adjacent areas. There are 41 municipal utilities in Michigan. In some cases, cooperative and municipal utilities own generation, but, in others, they enter into joint generation agreements. Both approaches are used in Michigan.

In recent years, three new types of entities have begun to enter the electric utility market. Independent power producers are private companies, not associated with the local utility, that build and operate electric generation plants and sell the power output into the market. In 2002, independent power producers built four new generating plants in Michigan.

Alternative electric suppliers are private companies that sell power at retail in competition with the local electric utilities. Alternative electric suppliers do not own distribution lines or deliver the power – they rely on the local utility to do that for a fee. To date, the Commission has licensed 26 alternate electric suppliers to operate in Michigan.

Independent transmission companies are private companies that own and operate one or more transmission systems. The two largest electric utilities in Michigan have sold their transmission assets to independent companies. Hence, the utilities now own the generation plants and distribution networks, but independent companies own the transmission that connects the two.

There are other organizations that are not directly involved in operations, but can have a significant impact on reliability. Regional transmission organizations (RTO) are composed of transmission companies (both independent and utility) within a given region. RTOs are responsible for coordinating access to and use of the transmission network. RTOs are subject to approval by the Federal Energy Regulatory Commission, which has jurisdiction over wholesale transactions and transmission of electricity in interstate commerce.

Section 1.2: Key Participants

The following is a list and brief description of electric industry participants relevant to the blackout of August 14:

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[2] All but one of the smaller investor-owned utilities (and the two largest) are subsidiaries of much larger holding companies.

- American Electric Power Company (AEP) – a large public utility holding company that operates in eleven states.[3] Its subsidiary, Indiana Michigan Power Company, operates in the southwest corner of Michigan.

- Consumers Energy Corporation – a large combined gas and electric utility, serving 1.7 million electric customers throughout most of the Lower Peninsula outside of the Detroit metropolitan area. It is a subsidiary of CMS Energy Company.

- The Detroit Edison Company – the largest electric utility in Michigan, serving 2.1 million customers in the Detroit metropolitan area. It is a subsidiary of DTE Energy Company and an affiliate of Michigan Consolidated Gas Company, which is a gas utility serving a similar territory.

- East Central Area Reliability Council (ECAR) – a voluntary organization designed to augment electric reliability through coordinated planning and operation of its members' generation and transmission facilities. The ECAR region includes Indiana, Kentucky, Michigan (Lower Peninsula only), Ohio, West Virgina, and small portions of four other states.

- FirstEnergy Corporation – a public utility holding company with seven electric utilities and a transmission subsidiary operating in New Jersey, Ohio, and Pennsylvania.

- Hydro One Networks, Inc. – one of four subsidiaries of Hydro One, Inc. It owns and operates 97% of the electric transmission lines in Ontario.

- International Transmission Company (ITC) – an independent transmission company that owns and operates the transmission system formerly owned by Detroit Edison. ITC is a subsidiary of the investment firm Kohlberg Kravis Roberts & Co.

- Michigan Electric Transmission Company (METC) – an independent transmission company that owns and operates the transmission system formerly owned by Consumers Energy. METC is a subsidiary of Trans-Elect, Inc.

- Midwest Independent System Operator (MISO) – a regional transmission organization covering all or parts of Indiana, Illinois, Iowa, Kansas, Kentucky, Manitoba, Michigan, Minnesota, Montana, North Dakota, Ohio, Pennsylvania, South Dakota, and Wisconsin. Both ITC and METC are members of MISO.

- North American Electric Reliability Council (NERC) – an umbrella organization formed in 1968 (after the New York blackout) to oversee the functions of ten regional reliability councils, including ECAR.

[3] In addition to Michigan, these are Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia.

- Ontario Independent Market Operator – a not-for-profit organization responsible for operating and regulating the wholesale electricity market in Ontario.

- PJM Interconnection – a regional transmission organization covering all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia, and the District of Columbia.

Section 1.3: Key Events from Michigan's Perspective

This section contains a summary of the key events leading to and following the blackout from Michigan's perspective. It is not intended to include all events that could arguably have affected the blackout. Several organizations (FirstEnergy, ITC, METC, AEP, PJM, MISO, NERC, and the U.S./Canada Power Outage Task Force) have issued sequences of events. All of these sequences are generally consistent. This report draws from all of these in order to set forth what we consider to be the significant events, as viewed from Michigan's perspective.

Section 1.3.1: Thursday, August 14, 2003

- 12:05:44 p.m. – AEP Conesville Unit 5, with a rating of 375 megawatts (MW), trips[4] off-line. Most sequences begin with this event and it is included here only for completeness. In our opinion, this was not an event connected to the blackout. Since this unit had been down for two months, it was not expected to be producing electricity that day. The unit, which is located in central Ohio, was out of service for a short period and was back on-line at 3:20 p.m., nearly an hour before the blackout.

- 1:14:04 p.m. – Detroit Edison Greenwood Unit 1, with a rating of 785 MW, goes off-line. Like the previous item, this event is included only for completeness, as it does not appear to be an event connected to the blackout. The unit experienced a boiler fuel trip at 12:45 p.m. The output of the unit was gradually reduced until it went off-line at 1:14 p.m. The unit, which is located north of the Detroit area, was brought back on-line and was producing about half of its rated capacity at the time of the blackout. However, other generators on the Detroit Edison system had been brought on-line to compensate for the capacity loss, so there was no overall reduction in output. The Michigan system was in balance prior to the last significant events before the blackout.

- 1:31:34 p.m. – FirstEnergy Eastlake Unit 5, with a rating of 597 MW, trips off-line. This is arguably the first of many events that cumulatively led to the blackout. The unit, which is located in northern Ohio, along the shore of Lake Erie, was still off-line at the time of the blackout and the output of the unit had not been replaced. According to the testimony of Peter Burg (chairman and CEO of FirstEnergy) before the U.S. House of Representatives Committee on Energy & Commerce, the Eastlake

[4] The term "trip" refers to the automatic removal from service of a unit.

Unit 5 tripped during the process of restoring the voltage regulator from manual to automatic control. According to Mr. Burg, this procedure was undertaken in order to stabilize reactive power output, so that the unit could later resume the requested voltage schedule. An ARS (automatic reserve sharing – a request for assistance to meet load when there is a loss on a utility's system) was initiated for 595 MW from within the ECAR region. Mr. Burg indicated that they planned to supply some of this by cutting a 300 MW sale into PJM.

- 3:05:41 p.m. – FirstEnergy Harding–Chamberlain 345 kilo-Volt (kV) line into northern Ohio trips.

- 3:32:03 p.m. – FirstEnergy Hanna–Juniper 345 kV line in northern Ohio trips. It has been reported that this line disconnected because it sagged into a tree.

- 3:41:33 p.m. – AEP/FirstEnergy Star–South Canton 345 kV line in northern Ohio trips. AEP reports that this line opened due to high load and a phase to ground trip. AEP owns 0.69 miles of this line and FirstEnergy owns 33.42 miles. The U.S./Canada Power Outage Task Force reports that, with this and the prior two transmission lines disconnected, the effectiveness of the transmission path from eastern Ohio into northern Ohio was reduced.

- 3:42 p.m. – Multiple smaller lines begin to trip open in northern Ohio.

- 3:45:33 p.m. – AEP Canton Central–Tidd 345 kV line in northern Ohio trips open and reconnects 58 seconds later. According to AEP, the Canton Central–Colverdale 138 kV circuit experienced six breaker operations in less than 3 minutes. This resulted in the 345/138 kV transformers being disconnected, isolating the 138 kV system from the 345 kV system. AEP owns 0.38 miles of the Canton Central–Cloverdale line and FirstEnergy owns 12.2 miles.

- 4:06:03 p.m. – FirstEnergy Sammis–Star 345 kV line in northern Ohio opens, completely blocking the 345 kV path from eastern Ohio into northern Ohio.

- 4:08:58 p.m. – AEP Galion–Muskingum River – Ohio Central 345 kV line in central Ohio opens due to high loading.

- 4:09:06 p.m. – AEP East Lime–Festoria Central 345 kV line in central Ohio opens due to high loading, blocking transmission paths from southern and western Ohio in northern Ohio.

- 4:09 p.m. – Six 138 kV lines from FirstEnergy Burger Unit substation open.

- 4:09 p.m. – FirstEnergy Burger Units 4 and 5, with ratings of 150 MW and 135 MW, trip.

- 4:09 p.m. – FirstEnergy Burger Unit 3, with a rating of 70 MW, is tripped manually.

- 4:09 p.m. – Power surges occur from southern Ohio, west to Indiana, north to western Michigan, east to the Detroit area, and south to northern Ohio.
- 4:09:27 p.m. – Majestic–Tomkins interconnection between METC and ITC in central Michigan exceeds its emergency rating.
- 4:09:27 p.m. – Bayshore–Monroe interconnection between ITC and FirstEnergy exceeds its emergency rating.
- 4:09:23 to 4:10:27 p.m. – Kinder Morgan plant in central Michigan, with a rating of 500 MW, but loaded to 200 MW, trips.
- 4:10 p.m. – FirstEnergy Harding–Fox 345 kV line in northern Ohio opens.
- 4:10 p.m. – Twenty generating units along Lake Erie in northern Ohio, loaded to a total of 2,174 MW, trip off-line.
- 4:10:36 p.m. – METC Battle Creek–Oneida and Argenta–Tompkins lines trip.
- 4:10:38 p.m. – Pontiac–Hampton and Jewell–Thetford interconnections between METC and ITC trip, isolating the METC system from ITC.
- 4:10:38 Midland Cogeneration Venture, loaded to 1,265 MW, trips.
- 4:10:38 p.m. FirstEnergy Perry–Ashtabula–Erie West 345 kV line trips, isolating northern Ohio from Pennsylavania.
- 4:10:39 p.m. – Power begins flowing in a giant loop from southern Ohio to Pennsylvania to New York to Ontario to Michigan to northern Ohio.
- 4:10:40 p.m. – Lemoyne–Majestic interconnection between ITC and First Energy trips.
- 4:10:40 p.m. – Allen Junction–Majestic–Monroe interconnection trips at Majestic and Monroe, which stops power flow to FirstEnergy's Allen Junction interconnection with ITC.
- 4:10:41 p.m. – AEP Fostoria Central–Galion 345 kV line opens.
- 4:10:41 p.m. – Lansing BWL interconnection with METC at Enterprise opens.
- 4:10:42 p.m. – Consumers Energy Campbell Unit 3, with a rating of 820 MW, trips.
- 4:10:42 to 4:10:43 p.m. – Detroit Edison loses 1,863 MW of generation.

- 4:10:43 p.m. Monroe–Bayshore interconnection trips, isolating ITC from First Energy.
- 4:10:43 p.m. – Consumers Energy Whiting Units 1 and 2 trip.
- 4:10:43 p.m. – Keith–Waterman 230 kV line, which connects Ontario with Michigan, opens.
- 4:10:40 to 4:10:44 p.m. – Four transmission lines disconnect between Pennsylvania and New York.
- 4:10:45 p.m. – Transmission lines disconnect in Ontario and New Jersey.
- 4:10:52 p.m. – Oneida interconnection between Lansing BWL and ITC opens.
- 4:10:46 to 4:10:55 p.m. – Transmission lines between New York and New England (except for Connecticut) disconnect.
- 4:10:50 to 4:11:22 p.m. – Ontario interconnections with New York open.
- 4:10:59 p.m. – Consumers Energy Whiting Unit 3 trips.
- 4:11:05 p.m. – Lansing BWL's Erickson plant trips.
- 4:11:39 p.m. – All major Detroit Edison generation is off-line and most units have no station power.
- 4:11:57 p.m. – Remaining transmission lines between Ontario and Michigan open.
- 4:12:49 to 4:14:22 p.m. – Lansing BWL Eckert Station Units trip, leaving it with no generation on-line and no interconnections.
- 4:15 p.m. – The power outage is essentially complete. A total of 2.3 million customers of Consumers Energy, Lansing BWL, and Detroit Edison are without power. The area affected in Michigan is all of the Detroit Edison service territory, Consumers Energy customers located near the Detroit Edison service territory, and the cities of Lansing and East Lansing and other areas served by the Lansing BWL.
- 4:30 p.m. – Michigan Public Service Commission (PSC) Staff arrive at the State Emergency Operations Center (SEOC) and initiate contacts with officials of Detroit Edison, Consumers Energy, Lansing BWL, and the U.S. Department of Energy (DOE) Emergency Operations Center in Washington, D.C.

- 5:00 p.m. – Michigan State Police (MSP) Emergency Management Division (EMD) activate SEOC.
- 6:00 p.m. – Governor Granholm and her staff arrive at SEOC.
- Evening – PSC Staff develop assessments, estimate recovery timeframes, and brief the SEOC staff, providing information on how to handle a power outage and on the safe use of generators for posting to the State government website.
- 10:00 p.m. – The Governor makes a televised address on WKAR-TV to the State on the power outage (see Appendix A-1).
- 10:00 p.m. – Consumers Energy reports 118,400 customers without power.

Section 1.3.2: Friday, August 15, 2003

- 12:44 a.m. – Marathon Refinery in Detroit is reported out-of-service.
- 4:21 a.m. – Lansing BWL reports that power has been restored to all 98,000 affected customers.
- 6:00 a.m. – Consumers Energy reports that 70,100 customers remain without power.
- 8:30 a.m. – Detroit Edison reports that 2,000,000 customers remain without power.
- 9:15 a.m. – The Governor issues a Declaration of State of Emergency (see Appendix A-2) for the counties of Macomb, Monroe, Oakland, Washtenaw, and Wayne.
- 9:16 a.m. – Executive Order No. 2003-10 (see Appendix A-3) is issued by the Governor suspending environmental specifications for gasoline required for use in southeastern Michigan.
- 10:00 a.m. – At the request of the PSC Staff, Detroit Edison representatives arrive at the SEOC.
- 10:00 a.m. – Detroit Edison reports 1,750,000 customers remain without power.
- Noon – The Governor holds a press conference on the power outage and recovery efforts with J. Peter Lark, Chair of the PSC.
- Early Afternoon – Consumers Energy reports 17,000 customers remain without power.

- Afternoon – PSC issues a press release urging Michigan citizens to take all reasonable steps to conserve energy in light of the devastating power outage throughout the northeast (see Appendix A-4).

- Afternoon – At the request of the Michigan Department of Environmental Quality (DEQ), the U.S. Environmental Protection Agency (EPA) provides the State with enforcement discretion on environmental specifications for gasoline required for use in southeastern Michigan until August 22, 2003.

- All day – PSC Staff continues monitoring restoration efforts and return to service of power plants not yet available to the grid.

- Afternoon – Consumers Energy reports power restored to all 100,000 affected customers.

- 10:00 p.m. – Detroit Edison reports that 500,000 customers remain without power.

Section 1.3.3: Saturday, August 16, 2003

- 6:30 a.m. – Detroit Edison reports power restored to all 2.1 million affected customers.

- PSC and Detroit Edison continue to monitor power loads and return to service of power plants not yet available to the grid. Customers are asked to reduce power usage, which prevented the need for a rotating blackout.

Section 1.3.4: Sunday, August 17, 2003

- The SEOC is deactivated.

Section 1.3.5: Monday, August 18, 2003

- The Commission issues an order in Case No. U-13859, directing an investigation into the extent, duration, and cause of the outage relating to Michigan customers.

Section 1.3.6: Wednesday, August 20, 2003

- J. Peter Lark, Chair of the Energy Advisory Committee, advises the Governor and the Energy Advisory Committee of an impending energy emergency due to dwindling gasoline supplies as a result of the power outage and damage to the Marathon refinery in Detroit.

- At the request of the DEQ, the EPA provides the State with enforcement discretion on environmental specifications for gasoline required for use in southeastern Michigan until September 3, 2003.

- U.S. Energy Secretary Spencer Abraham and Canadian Minister of Natural Resources Herb Dhaliwal meet in Detroit and agree on an outline to be used by the U.S./Canada Power System Outage Task Force in its investigation. The Task Force will determine cause and effect of the outage. Three working groups addressing the electric system, security, and nuclear issues will be established to support the Task Force.

Section 1.3.7: Thursday, August 21, 2003

- 4:00 p.m. – Executive Order No. 2003-11 (see Appendix A-5) is issued by the Governor, which rescinds the Declaration of the State of Emergency and declares an Energy Emergency for the State of Michigan, due to loss of gasoline supplies as a result of the damage to the Marathon refinery and the temporary shutdown of other Midwest refineries supplying the Michigan market.

- 4:02 p.m. – Executive Order No. 2003-12 (see Appendix A-6) is issued by the Governor, which continues in place the suspension of environmental specifications for gasoline required for use in southeastern Michigan.

Section 1.3.8: Saturday, August 23, 2003

- The Marathon refinery in Detroit resumes production of petroleum products, including gasoline, that meet the specifications required under air quality rules for southeast Michigan. The refinery, which was shutdown for eight days following the outage, lost nearly 500,000 barrels of petroleum product production, roughly half of which was gasoline (about 11 million gallons). This is equal to about 3 percent of the projected statewide gasoline demand in August. However, the concentration of the lost supply in southeast Michigan made the area's shortfall larger than this figure suggests for that region.

Section 1.3.9: Wednesday, August 27, 2003

- Secretary Abraham and Minister Dhaliwal, as Co-Chairs of the U.S./Canada Power System Outage Task Force, announce the membership of the three working groups that will support the Task Force. Participating from Michigan on the Electric Systems and Nuclear Power Working Groups will be J. Peter Lark, PSC Chair. Participating on the Security Working Group will be Colonel Michael C. McDaniel, Assistant Adjutant General for Homeland Security for Michigan.

Section 1.3.10: Thursday, August 28, 2003

- At the request of DEQ, the EPA provides the State with enforcement discretion on environmental specifications for gasoline required for use in southeastern Michigan until September 15, 2003, at which point the summer environmental specifications are no longer in effect.

Section 1.3.11: Wednesday, September 3, 2003

- Governor Granholm and PSC Chair Lark testify before the U.S. House of Representatives Committee on Energy and Commerce on the power outage.

Section 1.3.12: Tuesday, September 30, 2003

- Executive Order No. 2003-16 (see Appendix A-7) is issued by the Governor rescinding the Declaration of Energy Emergency for the State of Michigan.

PART II

ELECTRIC TRANSMISSION

Section 2.1: Scope of the Investigation

Although the electric transmission events that led to the blackout were regional, and perhaps national in scope, the focus of this investigation has been on the impact to Michigan. In the order initiating this inquiry, we concluded "that there should be a Michigan-specific investigation into: (a) the extent, duration, and causes of the outage relating to Michigan customers; (b) the reaction of Michigan electric utilities and transmission grid operators … to the outage and the events preceding it: (c) a comprehensive assessment of the power restoration efforts by Michigan companies; and (d) recommendations designed to prevent future disruptions."

The central geographic focus of the blackout was on the "Lake Erie Loop." The Lake Erie Loop is that portion of the eastern interconnection of the electric grid that runs around Lake Erie, most directly impacting the border states of Michigan, Ohio, Pennsylvania, New York, and the Canadian Province of Ontario. However, as evidenced by the blackout, other states were also affected as a result of the extensive interconnectedness of the electric grid running throughout the entire eastern interconnection, which covers much of the eastern portion of the country east of the Rocky Mountains.

Our overall investigative focus has been prospective. Although we examined factors contributing to the cause of the blackout, the principal objective was to identify reliability issues and concerns that were uncovered from the investigation that can provide guidance on ways to strengthen overall grid reliability. Although a comprehensive array of options has been included, our focal point of emphasis was regional grid coordination.

It is important to emphasize that this report does not attempt to establish the "root cause" of the blackout or directly assign blame. That responsibility is best relegated to the U.S./Canada Power System Outage Task Force, which set determination of root cause among its principal objectives. That Task Force is much better positioned to address the root cause question. Clearly, compared to the Commission, it has significantly greater access to information and the substantial resources needed to dig deeply into causal issues. Likewise, the scope of the international investigation is much broader geographically than the Michigan study, which is concentrated primarily in and around Michigan. Finally, as discussed more fully later in this report, we conclude that the events leading up to the blackout occurred in Ohio, which is beyond the purview of this Commission.

In conducting this investigation, the following questions were addressed:

- What happened?
- How was Michigan impacted?
- What are the lessons learned?
- What can be done to prevent a blackout like this from recurring in the future?

Section 2.2: Study Approach

In conducting the investigation, we utilized a wide variety of information sources. The following are the principal data sources relied upon:

(1) Published information from a wide variety of sources was utilized. In the wake of the blackout, numerous reports, news releases, and articles were published by a variety of sources, both public and private. Among the information sources reviewed were professional reports, analyses from industry and academic experts, testimony from State and Congressional hearings, trade press articles, governmental statements and press releases, and many newspaper and magazine articles. Although often redundant, the flood of information following the blackout proved quite helpful in piecing the events together into a comprehensive picture.

(2) Interviews with key participants charged with grid reliability were a crucial source of information to the investigation. Key to the study investigating regional coordination aspects of the blackout was information obtained from extensive interviews with various individuals with reliability and operational responsibility throughout the region. Included in these interviews were representatives from:

- Michigan's two major transmission companies operating the transmission grid in the lower peninsula – the International Transmission Company and the Michigan Electric Transmission Company.

- The American Electric Power Company transmission reliability coordination and transmission operations personnel.

- The Michigan Electric Coordination System – which oversees the local reliability control areas for ITC and METC covering most of the Lower Peninsula including the service territories of Detroit Edison and Consumers Energy and is the control center where certain reliability functions are jointly managed under the decentralized reliability system within the Midwest Independent System Operator.

- The Midwest Independent System Operator.

- The PJM Interconnection – the regional transmission organization for the Mid Atlantic states and some key Midwestern utilities including AEP.

- The New York Independent System Operator (New York ISO).

- The Ontario Independent Market Operator (Ontario IMO).

- The Federal Energy Regulatory Commission.

(3) Primary data was also very important to the investigation. Review of reliability and operations control room telephone conversations from all the above listed organizations, except the Ontario IMO and the New York ISO, was instrumental to examination of grid management

issues and problems, especially communications coordination among personnel from the various reliability controllers within the region. Although much of the relevant data from these communication links had already been reported through the media, the opportunity to directly examine the actual conversations that took place helped to empirically verify the accuracy of those reports. The additional detail provided by the full text of those conversations also significantly enriched our understanding of what took place in the reliability centers within the region affected by the blackout.

Although many and varied sources of information were carefully evaluated and cross-checked to ensure reliability in the conduct of this investigation, in the final analysis, this report's findings, conclusions and recommendations largely reflect the professional expertise and judgment of the Commissioners and our Staff. Staff assignments to perform the study were made with that in mind, coupled with an appreciation of the importance of the blackout investigation. The expertise and analytical capability of the investigation team encompasses considerable academic training, along with extensive electric industry knowledge and professional experience.

Section 2.3: Events of August 14, 2003

As previously mentioned, this investigation does not intend to identify the root cause of the blackout. Rather, it identifies the significant events leading up to the blackout as an aid to analyzing what steps are needed to help prevent a reoccurrence.

A list of specific events leading up to the blackout is presented in Section 1.3. A review of this timeline indicates that all of the events in the two and one-half hours preceding the power surges that occurred at 4:09 p.m. involved FirstEnergy or AEP facilities in Ohio. In addition, FirstEnergy's Davis Besse nuclear plant had been out-of-service for some time. It appears that, with the Davis Besse nuclear plant off-line, the tripping of Eastlake Unit #5 was a major event in the northern Ohio region. FirstEnergy was left in a precarious position as far as meeting its load on that day. Power had to come from other sources in order to meet the requirements of the FirstEnergy system. FirstEnergy did initiate a request for automatic reserve sharing and MECS did respond to this request. Nonetheless, lines in Ohio soon began to open. Although information provided by MISO and FirstEnergy indicate that the first lines that opened were not loaded to capacity, it appears that the opening of those lines quickly contributed to the evolving problem. As the number of lines opening in Ohio increased, there were fewer and fewer paths available to serve the demand coming from northern Ohio. According to data from Michigan transmission operators and the MISO, at about 4:09 p.m., over 2,000 MW of power was suddenly pulled from west to east through Michigan and into northern Ohio. Voltage on the Michigan grid became unbalanced. Seconds later, the flow suddenly reversed and over 2,000 MW were pulled into Michigan from the east, again attempting to reach load in northern Ohio. There can be little doubt, based on the sequence of events and magnitude of the power flow reversals, that disturbances in Ohio led to the blackout. Evidence strongly suggests these disturbances led to an internal load balancing collapse of the FirstEnergy system, which ultimately precipitated the blackout.

All of the people interviewed for this investigation agreed that August 14, 2003 was a normal summer day. However, there were some indications that the day was turning out to be hotter and more humid than had been predicted. Early in the day PJM issued a "high load voltage warning." In our interviews with Michigan and other state transmission operators, no specific supply problems were noted and the overall supply situation for the region was very adequate. Transmission operators and reliability coordinators (RCs) had been communicating normally during the day. MISO had been working with Cinergy[5] to relieve congestion in its territory.

In the very last minutes preceding the blackout, Michigan operators saw large flow swings of over 2,000 MW. As a result of the declining voltage, the protective devices on three Michigan power plants tripped. According to ITC records, within seconds it was in full voltage collapse with over 30 transmission lines opening. METC and ITC connections separated as the relays responded to programmed settings. Several more plants in DTE's service area tripped. Most of ITC's system was blacked out, only a few scattered areas still had electricity. METC's system remained largely intact, although there were some scattered outages.

The Greenwood power plant outage on the Detroit Edison system was not a factor contributing to the blackout. The Greenwood plant experienced a fuel trip at approximately 1:14 p.m. and was returned to service in less than 45 minutes at about 1:57 p.m. During the Greenwood outage power from other generation facilities on the Detroit Edison system was brought on-line for replacement of the lost power from the Greenwood generation unit. The facility was fully resynchronized to the system more than two hours before the blackout.

The first event that MISO observed was the opening of the FirstEnergy Hanna–Juniper line at 3:32 p.m.[6] MISO was unaware that the FirstEnergy Harding-Chamberlin line had opened at 3:06 p.m. because MISO only follows "key facilities." At the time of the blackout, the Harding-Chamberlin line had not been identified by FirstEnergy as a key facility.

According to the MISO telephone transcripts, MISO called First Energy at 3:43 p.m. and questioned FirstEnergy about the Hanna-Juniper line. The FirstEnergy operator was not able to respond to MISO's questions and said that he didn't know, that he would have to take a look. MISO requested that FirstEnergy call it back. At 4:04 p.m., FirstEnergy called MISO and stated that they had some problems. The FirstEnergy operator still seemed unsure about exactly what was happening. The operator lists a number of lines that are "off", the Eastlake Plant unit that had gone off-line earlier in the day and the Perry plant that was "having a hard time maintaining voltage". The FirstEnergy operator then asks MISO what it has going on. When MISO responds that FirstEnergy Hanna-Juniper line is open, the FirstEnergy operator questions that. MISO responds that it had discussed this with FirstEnergy earlier. The FirstEnergy operator states that they have "no clue" and the computer is "giving us fits." A FirstEnergy control room operator told a MISO technician minutes before the blackout, "We don't even know the status of some of the stuff around us." The MISO operator states that MISO thought FirstEnergy was trying to

[5] Cinergy Corporation provides natural gas and electric utility service in Indiana, Kentucky, and Ohio.
[6] FirstEnergy was not a member of MISO on August 14, although MISO was its reliability coordinator. On October 1, 2003, American Transmission Systems, Inc., the transmission subsidiary of FirstEnergy became part of MISO through GridAmerica LLC. GridAmerica, a subsidiary of National Grid USA, manages the transmission system of FirstEnergy, Northern Indiana Public Service Company, and Ameren Corporation.

figure this out. The FirstEnergy operator says they are trying to and then asks if the MISO sees anything else going on around them. The MISO mentions that Cinergy had some lines opening earlier in the day, but the FirstEnergy operator responds that that shouldn't have affected them. The transcript ends in mid-sentence. Based on the MISO telephone transcripts, MISO did not talk to any other control areas about the situation at FirstEnergy. Thus, MISO was unable to communicate effectively with its members, and FirstEnergy was unable to communicate effectively with its reliability coordinator, MISO.

It is important to note that Peter Berg (the CEO of FirstEnergy), in his Congressional testimony, stated that although First Energy was experiencing problems with its energy management computer system, MISO had information about FirstEnergy's system and could have been used as a backup. As is discussed above, MISO did not have access to all of FirstEnergy's information, in that MISO only had information on the key facilities that had been identified by FirstEnergy. However, if FirstEnergy was relying on MISO to provide back up information, then it makes sense that FirstEnergy should have contacted MISO to request that back up. Based on our review of the MISO telephone transcripts, there is no indication that FirstEnergy called MISO to report their dilemma until 4:04 p.m. This was several minutes after MISO had contacted FirstEnergy to discuss the Hanna-Juniper line. During the call that was initiated by MISO, FirstEnergy did not describe any problems. It should be noted that FirstEnergy did not have any problem contacting MISO after the event. The MISO transcripts show a number of calls from FirstEnergy to MISO asking for assistance in the restoration efforts.

AEP and PJM also talked to FirstEnergy and were talking to each other. Based on our review of these calls, FirstEnergy provided less than enlightening information. Both AEP and PJM appear to have gotten the impression, either directly or indirectly, that FirstEnergy was having computer problems. AEP also called PJM when AEP saw that the South Canton–Star line was becoming overloaded. On the telephone transcripts that we reviewed, AEP initially thought that the South Canton–Star line was a FirstEnergy line. After AEP determined that the line was jointly owned, AEP and PJM began discussing the issuance of a Transmission Loading Relief (TLR)[7] procedure. Before the TLR could be issued, the South Canton–Star line opened. As a result of that line opening, PJM called FirstEnergy to discuss the contingency line (Sammis-Star), a line that belonged to First Energy. First Energy was unable to provide any meaningful assistance to PJM and told PJM to talk to AEP.

The two reliability coordinators for the Midwest utilities, MISO and PJM, did call FirstEnergy shortly before the blackout to try and discuss potential problems they were observing on the FirstEnergy system. As described in the detail of the calls discussed above, the response from First Energy was confused, at best. Earlier in the day FirstEnergy had called MISO to report a discrepancy in the outage report on the time that the Eastlake plant went out of service. FirstEnergy indicated during that call, which occurred at 2:24 p.m. (over 50 minutes after Eastlake went out of service), that they did not know why the plant had tripped. Based on the review of telephone transcripts that we reviewed, FirstEnergy did not contact MISO concerning any other problems that FirstEnergy was having that afternoon until 4:04 p.m. – only 5 minutes before the cascading blackout events began.

[7] Transmission Loading Relief is a process that allows reliability coordinators to curtail transmission service.

Immediately after the blackout, grid restoration efforts were commenced. MISO kept a telephone line open so that all parties involved could communicate with each other and assist each other with restoration efforts. The code of conduct, which requires independent functioning of transmission operators and affiliate wholesale marketers except in an emergency, was appropriately suspended to permit communication channels to be fully opened. Overall the grid restoration went relatively smoothly throughout the region.

Section 2.4: Analysis

Section 2.4.1: Electric Industry is in Transition

Understanding critical changes shaping the electric industry is important to understanding how the events of August 14 unfolded and what can be done to reduce the likelihood of a recurrence.

The electric industry looks very different today than it did when it first emerged at the turn of the century. Most notably, the nation's electricity delivery system has grown and evolved from a very local, insular, largely self-sufficient network to one that is highly interconnected and regionally interdependent. The August 14th blackout was a clear reminder of just how interdependent the electric grid has become.

It is somewhat ironic that grid interconnections, the mechanism that physically enabled the blackout to spread through such a wide area, were originally established to improve reliability. In the electric industry's infancy the transmission network served exclusively as the mechanism used to move electric power from generating plants to customer load within a local utility company's service territory. However, as the industry matured, companies soon discovered that by linking with neighboring local utility companies they could assist each other in times of emergency and improve overall reliability of service to their customers. Companies were mutually benefited through sharing of supply reserves.

Interconnecting utility transmission facilities over larger geographical areas, while increasing overall reliability, also created dependence among independently operated utility systems. This relationship, as illustrated by the blackout, means connected utility systems are now vulnerable to events occurring on other utility systems linked to the chain. While no credible argument can be made advocating that grid interconnection is not beneficial to overall industry reliability improvements, the tradeoff is that disturbances on one system, if not contained, can cascade throughout the interconnected grid as they did on August 14. Thus, while grid interconnection can be expected to reduce the probability and duration of an outage, it also introduces the possibility of a significant event or a series of smaller events on one system triggering a large outage. The key challenge going forward is to take steps to localize disturbances to prevent them from cascading.

Section 2.4.2: Electric Industry is Responding to Competitive Pressures

Over the past 20 years real (inflation adjusted) electricity prices paid by consumers have significantly decreased. Since 1990 real electric prices have dropped nearly 12% nationally, almost 18% in the ECAR States, and 21.5% in Michigan (see Figure 2.1). The largest declines are in the Midwest where manufacturing demands for efficiency are most intense. Among the more significant factors driving these recent efficiency gains is the increasingly competitive wholesale electricity market that has emerged during this period.

FIGURE 2.1

Average Retail Prices of Electricity, 1990-2001

(Inflation-Adjusted Cents per Kilowatthour)

Year	Michigan Total		Regional Total		National Total	
	Real [1]	% Increase	Real [1]	% Increase	Real [1]	% Increase
1990	8.8852	0.0%	7.1982	0.0%	8.2197	0.0%
1991	8.7006	-2.1%	7.0457	-2.1%	8.1440	-0.9%
1992	8.5273	-4.0%	6.8218	-5.2%	8.0425	-2.2%
1993	8.2153	-7.5%	6.7074	-6.8%	7.9704	-3.0%
1994	7.9751	-10.2%	6.5380	-9.2%	7.7687	-5.5%
1995	7.7656	-12.6%	6.3838	-11.3%	7.5860	-7.7%
1996	7.6678	-13.7%	6.2685	-12.9%	7.4102	-9.8%
1997	7.4727	-15.9%	6.1365	-14.7%	7.2757	-11.5%
1998	7.4391	-16.3%	6.1672	-14.3%	7.0685	-14.0%
1999	7.3782	-17.0%	6.0912	-15.4%	6.8949	-16.1%
2000	7.2517	-18.4%	5.9813	-16.9%	6.9463	-15.5%
2001	6.9788	-21.5%	5.9254	-17.7%	7.2600	-11.7%

1 In inflation-adjusted (2001) dollars, calculated by using Gross Domestic Product deflators. Source is: Budget of the United States Government, Table 10.1 –Gross Domestic Product and Deflators Used in the Historical Tables: 1940-2005, (wk4 or xls).

Prepared by: Competitive Energy Division, Michigan Public Service Commission, September 2003.

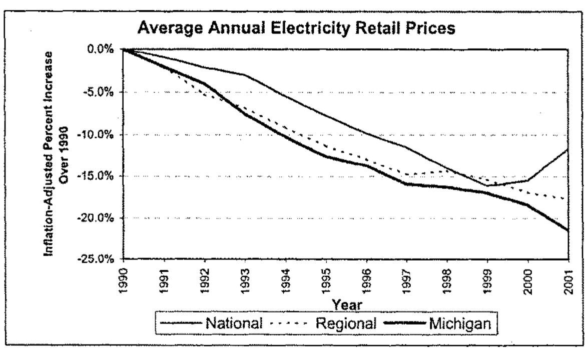
Data Source: Energy Information Administration, U.S. DOE, Electric Power Annual 2001 Table 7.4, Annual Energy Review 2001

Table 8.6, Form EIA-861 Database

http://www.eia.doe.gov/cneaf/electricity/epa/epat7p4.html

EIA sales_states.xls, evenue_states.xls

http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html



In recent years demands on the electric industry to power our nation's growing economy and satisfy consumer needs has provided the world standard for safety, convenience, and comfort at affordable prices are unprecedented. By and large, the industry has stepped up to the challenge. Since 1990 demand (nationally, regionally and in Michigan) has increased by about 30% (see Figure 2.2). Not only has this significant increase in demand been met, it has been accomplished at lower cost to consumers. Nevertheless, increased demand is a factor stressing the grid's reliability capability. Industry restructuring has also placed stress on grid reliability. Opening the electric industry to competition has introduced new participants (such as independent transmission companies, independent generators, power marketers and energy traders) and expanded the number of power exchange transactions as well as the distances power is transported. Growing pains are also evident as the transmission network struggles to accommodate the sudden and significant increase in power transactions over extended geographic areas. Cost-effective investment is needed to alleviate critical bottlenecks and expand transport capability in some areas. Likewise, significant attention to measures to improve regional grid coordination and management is essential to both electric grid reliability and efficiency improvements.

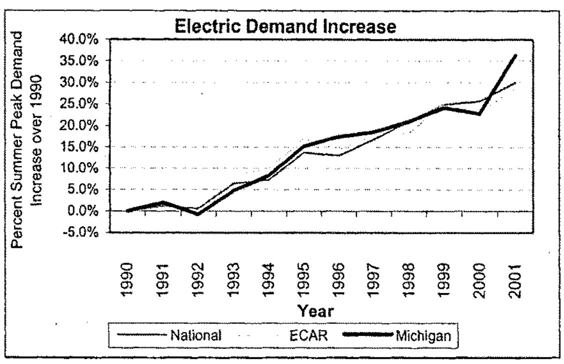
Competitive electric industry restructuring, while a factor stressing the grid within the Lake Erie loop, is not the cause of the August 14th blackout. Electrons moving through the grid follow the laws of physics, not economics. The grid is indifferent to whether electricity moving through the wires is produced and sold under a market structure that is competitive, regulated or a hybrid of the two. Our investigation of the August 14th blackout found no basis to dispute this conclusion. However, what we did discover is that in the current transition, the "rules of the road" defining the relationship between reliability and efficiency need considerable revision if both reliability and efficiency are to effectively coexist in today's complex restructuring industry. The challenge is to make adjustments to the grid and its management that will continue to make the two critical objectives complementary.

FIGURE 2.2

Michigan, ECAR, National Electric Peak Demand
(Non-coincident Peak in Megawatts)

Year	Summer Michigan				Summer ECAR		Summer U.S.	
	CE	DTE	Total	% Increase over 1990	Total	% Increase over 1990	Total	% Increase over 1990
1990	5,891	9,032	17,905	0.0%	79,258	0.0%	545,537	0.0%
1991	6,084	8,980	18,247	1.9%	81,539	2.9%	551,705	1.1%
1992	5,939	8,704	17,759	-0.8%	78,550	-0.9%	548,707	0.6%
1993	6,226	9,362	18,758	4.8%	85,930	8.4%	580,753	6.5%
1994	6,502	9,684	19,386	8.3%	87,165	10.0%	585,320	7.3%
1995	7,158	10,049	20,621	15.2%	92,819	17.1%	620,249	13.7%
1996	7,167	10,377	21,032	17.5%	90,798	14.6%	616,790	13.1%
1997	7,315	10,305	21,224	18.5%	93,492	18.0%	637,677	16.9%
1998	7,246	10,704	21,670	21.0%	93,784	18.3%	660,293	21.0%
1999	7,460	11,018	22,223	24.1%	99,239	25.2%	681,449	24.9%
2000	7,306	10,730	21,994	22.8%	97,557	23.1%	685,816	25.7%
2001	8,289	11,860	24,417	36.4%	102,161	28.9%	709,166	30.0%

Total U.S. noncoincident peak demand is for contigous U.S. without Alaska or Hawaii.
Prepared by: Michigan Public Service Commission
Sources: May 2003 Michigan Electric Sales Forecast, 1990-01, Energy Information Administration, U.S. DOE, Form EIA-861 Database, ECAR, National data source: EIA Electric Power Annual Table 3.1, EIA Annual Energy Review 2001 Table 8.8, Form EIA-411
see http://www.eia.doe.gov/cneaf/electricity/epa/epat3p1.html
http://www.eia.doe.gov/emeu/aer/elect.html



Section 2.4.3: Grid Reliability Responsibility

The North American Electric Reliability Council (NERC) has operated since 1968 as a voluntary organization with the goal of ensuring that the electric transmission system is reliable, adequate and secure. NERC does this through two primary tools: planning standards and operating policies. Planning standards are used in the development of new transmission systems. The operating policies are made up of standards, requirements and guides with the intent that no system will impact the integrity of any of its interconnected systems. The primary responsibility for actually carrying out the operating policies is on the control area. A control area, as defined by NERC, is an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the Interconnection.

Reliability coordinators (RC) act under the auspices of NERC and are responsible for ensuring the operational reliability of the interconnections (the facilities that connect two systems or connect a system to a non-utility generator). The reliability coordinator plans for next day operations, analyzes current day operating conditions and implements the transmission loading relief (TLR) procedure. The TLR procedure is a key component of the reliability coordinator's job since it is intended to relieve overloaded conditions on a transmission system. In a critical situation, the reliability coordinator has the authority to direct control area operators in its reliability area to do whatever is necessary to relieve the situation. The reliability coordinator is also required to advise all control areas in its reliability area and all other reliability coordinators if an emergency exists in its area. This notification can be done through the RCIS (Reliability Coordinator Information System), a computer program that posts information to a central web site that can be accessed by all reliability coordinators and control area operators.

Enforcement of the standards, in practice, has been accomplished through voluntary compliance. Currently, NERC portrays its compliance process as mandatory, but not enforceable. NERC, through its regions, conducts compliance reviews and issues enforcement advisories. The enforcement advisory can be in the form of an award for good performance or a simulated sanction or penalty. NERC uses a simulated sanction or penalty because it does not have the authority to issue an actual penalty. Under the NERC RC Procedures, all Control Areas must comply with a directive from the RC. The 2002 NERC Compliance Enforcement Program Report indicates that there were 444 violations involving operating measures in 2002. These violations resulted in $9 million of simulated sanctions, which could have been actual penalties had penalty provisions been in place and enforced.

FERC is the regulatory agency that oversees the interstate transmission of electricity. The agency regulates the economic aspects of interstate transmission and wholesale sales of electricity. FERC states that it may not have regulatory authority over the construction of transmission or generation facilities, except for hydroelectric facilities.

Regional grid coordination and management must be strengthened through strong and properly configured RTOs. Effective regional grid reliability coordination and management is key to improving reliability on an increasingly interdependent transmission grid. In the Midwest, this should be accomplished by mandatory RTO participation by transmission owners and operators.

Ways to quickly resolve parochial interests and move toward effective regional solutions to regional reliability issues must be forged.

Mandatory RTO participation, where FERC deems it necessary, is essential. RTO development in the Midwest underscores the importance of having a single RTO in the region. Serious configuration and seams problems are stifling RTO development in the Midwest region and threaten the region's ability to effectively manage reliability. Failure to correct these problems could deliver a fatal blow to effective RTO development in the Midwest. The best-designed reliability standards are of little value if they are not uniformly and widely enforced. The system is only as strong as its weakest link. Allowing transmission operators within an interconnected grid to opt out of the RTO or to dictate the terms of RTO participation, as often occurs under the present voluntary system where competing RTOs in the Midwest vie for prospective members, is a recipe for disaster. On August 14th, no one chose to be a victim of the blackout. No one should likewise be excused from participation in those efforts necessary to prevent a future occurrence.

Section 2.4.4: Effect of Competition

Although a factor, electric industry restructuring did not cause the blackout. Primarily an outgrowth of change, the impact of competition on reliability is a factor that can be effectively managed. However, the relationship between reliability and efficiency must be clearly established such that reliability reigns supreme where conflicts surface between reliability and efficiency. This fundamental principle must be clearly established, understood and rigorously enforced.

Reliability enforcement decisions should be placed in the hands of an independent party. Placing authority or any significant control over grid reliability decisions in the hands of companies with a commercial interest at stake must be prevented. Removing the temptation to avoid implementation measures that may be needed to localize or contain a disturbance is a must. There is no question that a reliability coordinator's decision to take action to shed load during a disturbance must take precedence over the commercial impact of the decision. We did not find any evidence to conclude that such a conflict played a role on August 14. However, we note that both companies experiencing disturbances, FirstEnergy and AEP, still play a significant role in the execution of reliability coordination monitoring and decision-making within their respective RTOs. Both AEP and FirstEnergy are vertically integrated utility companies with a financial stake in the commercial operations for energy sales and delivery (transmission and distribution) to their utility customers. This potentially conflicting responsibility is problematic.

Section 2.4.5: Grid Investment

Strategic grid investment is needed to effectively accommodate industry changes necessary to continue to meet high industry standards for reliability and efficiency. According to the NERC's *Reliability Assessment 2002-2001* issued in October 2002, the number of TLRs requiring curtailment of firm transactions increased from zero in 1998, to 1 in 1999, 7 in 2000, to 16 in 2001, to 18 in the first six months of 2002. This suggests a transmission grid that is under increasing pressure to meet the demands placed upon it. That NERC report indicated that "portions of the transmission systems are reaching their limits as customer demand increases and the systems are subject to new loading patterns resulting from increased electricity transfers."[8]

Customers expect and deserve reliable and competitively priced electricity. With that in mind, grid investment to expand and upgrade the transmission system should be cost-effective so that investment is strategically targeted to cost-effective congestion and growth needs. According to the NERC report, only 155 circuit miles of new transmission is planned for the ECAR region through 2006 out of an existing base of 16,207 miles. Moreover, no new transmission is planned in ECAR during the 2007-2011 time period. This equates to an increase in transmission lines of less than 1% over the next 8 years. For comparison, in the United States as a whole, transmission lines are expected to grow by approximately 6% during the same period. This suggests that consideration should be given to additional transmission lines in this region.

Section 2.4.6: Grid Reliability

Grid reliability coordination and management must be accomplished on a regional basis. The blackout served as a wake-up call to accelerate regional coordination of all aspects of grid development and operation. Parochial utility and state interests must give way to more effective regional grid planning, operation and management to advance grid reliability objectives. In particular, actions must by expeditiously undertaken to establish strong and effective RTOs throughout the Midwest, Mid–Atlantic, and New England regions, which have become increasingly interdependent and generally supportive of RTO development.

Section 2.4.6.1: Key Facilities and Other Information

The RCs need to see the big picture, including all key facilities. The MISO is already addressing the use of key facilities. FirstEnergy, for example, has gone from 35 to 90 key facilities that are available to the MISO for detailed on-going review. ITC and METC have indicated that they have made all of their data available to the MISO. Other control areas that are members must also make all of their data available to the MISO. The RCs need to see into the areas that are connected to them. The MISO and PJM had the ability to see some of this but could not see all of the pertinent areas. The RCs should work together to determine what information they need in order to bring the big picture into focus. The interconnections that are common all across the country are making the ability to see a more expansive, comprehensive and timely view of the transmission system increasingly essential to maintaining reliability. System monitoring capability must be state of the art to successfully accomplish this demanding task.

[8] Quotation is from page 20 of the report. Interestingly, that page begins with the statement that: "North American transmission systems are expected to perform reliably in the near future."

Section 2.4.6.2: Reliability Control Operators

There are indications that more or better-trained reliability control operators may be needed. There should be a sufficient number of well-trained operators in the control room to handle any number of emergencies that might arise. On the MISO transcripts, reliability operators spent considerable time dealing with an emergency on the Cinergy system. While that event did not directly impact the events leading up to the blackout, it did appear that the MISO operators were having some difficulty keeping up with the numerous functions that needed their attention that day. In fact, the MISO's state estimator, which is one of its system monitoring tools, was not operating properly for several hours, and it appears that in the confusion, no one noticed. The control centers must be properly staffed and the operators properly trained, so that in an emergency situation adequate resources are available to respond to the emergency and to the ongoing system operation.

Control room equipment and operations should be thoroughly examined to ensure they are state of the art. The grid is a most complex and interdependent network. Individuals responsible for monitoring the grid and deciding when action is appropriate to prevent outages or isolate systems to prevent outages from cascading face a daunting challenge. Reliability control room operators must be properly trained, equipped, and provided with appropriate protocols to carry out these most important responsibilities.

Good communications are critical. The transmission grid is becoming more and more interconnected. This is not going to change; in fact, the trend is likely to increase. The interconnections provide for increased reliability and assistance during critical times. A communications chain needs to be established and adhered to by all of the entities. In the past, a control area may have only had to call its neighbor, and all of the operators probably knew each other by name. Now, the control area has to determine whom it should call. On the list is the RC (if the RC is different than the control area), the transmission operations centers (generally the utility or independent transmission company that actually operates the controls), and the neighbors (control areas that are connected). On the day of the blackout, there was confusion. AEP was calling FirstEnergy directly, AEP was calling PJM, PJM was calling FirstEnergy, PJM considered calling MISO but did not have time before events started to cascade. Another problem seemed to be that callers did not always know who they were talking to. There were sometimes two or three exchanges on "who is this", "who are you with", "what is your responsibility". A communications chain would also ease this problem, because each link in the chain would know who they are supposed to call and who is calling them.

Another significant part of communications is the communication system itself. The telephone is still being used to a large extent to communicate with others regarding reliability concerns. The whole system should be reviewed and the expanded use of computers should be explored. With e-mail and instant messaging now available, communications could be put in writing, which could provide clarification and consistency. Systems that are already in place, such as the RCIS, should be utilized more extensively. The phone system itself should also be examined to provide better and more reliable phone service. Based on our interviews with transmission operators, the phone service at the Michigan control center was sporadic after the blackout.

Communication protocols should be developed to more effectively address regional reliability coordination needs. Protocols directing appropriate procedures for information exchange among reliability coordinators are much needed. Much confusion was evident in reliability coordination control centers on August 14th regarding communication protocol.

Staffing qualifications, training and levels should be reviewed. Although our investigation did not uncover any specific staffing problems, our review of control room conversations and interviews with industry representatives led to the conclusion that operators may have been stretched to their limits on August 14th. In light of significant industry changes and growing electric grid demands, control room staffing levels and training needs should be carefully examined. We recommend that a comprehensive investigation of reliability control room staffing issues be undertaken by NERC with FERC oversight. Any deficiencies identified from the investigation should be promptly corrected.

Section 2.4.6.3: Reliability Standards

Mandatory reliability standards are needed. Many of the industry expert testimonies, articles and reviews of the blackout, along with responses to our interview questions, strongly urged the implementation of mandatory reliability standards. This report concurs with that conclusion. The requirement that standards be applied, with a resultant penalty if they are not, is a critical factor in reliability assurance.

Section 2.4.6.4: Reactive Power

Reactive power is that component of total power that is needed to maintain voltage and permit active power to be delivered. It is commonly measured in volt-ampere reactive (VAR) for small units and mega-VARs (MVAR) for large units. The requirement for reactive power to maintain grid integrity has become more important as electricity is transported greater distances because reactive power is consumed locally and cannot be transported long distances. The increased number of independent power producers has also contributed to this concern. On August 14, several entities were requesting reactive power support. The specific details involving reactive power on August 14 are discussed in Section 3.3.[9] In our opinion, RTOs should take the lead on ensuring that there is adequate reactive power support on their systems. This need can be addressed by requiring all power producers to provide reactive power support in sufficient amount and requiring transmission owners to consider adding more capacitors to the system in their planning process.

Reactive power issues are receiving more attention as a result of the blackout. On October 15, 2003, NERC sent a letter to all control areas and reliability coordinators. NERC requests that several near-term actions be taken, including seven involving the management of voltage and reactive power. These actions include: (1) establishing daily voltage/reactive management

[9] Reactive power issues overlap transmission and generation. Reactive power is necessary to maintain voltage on the transmission grid, but it is provided by local generation. This is the reason that the details are discussed in this report under utility operations rather than transmission.

plans, (2) ensuring reactive power supplies are verified and available, (3) having sufficient reactive power reserves, (4) maintaining voltage schedules, (5) reporting low voltage conditions, (6) ensuring generators have automatic voltage regulation, (7) coordinating potential differences of voltage criteria and schedules between systems. We believe that these are appropriate first steps to addressing the reactive power issues highlighted by the blackout.

Section 2.4.6.5: RTO Authority

The authority of the RTO should be clear and enforceable. Overall, the RTO should have the authority to enforce directives that are made to preserve grid integrity, especially during a time of emergency. The expansion of the RTOs seems to have led to a situation in the Midwest where the RTOs vie for transmission owners. The agreement that the transmission owner signs with the RTO must be geared toward ensuring the reliability of the system. PJM noted that its contracts with its market participants give it additional ability to oversee the system. As the newer RTOs move toward establishment of a market, they must also make sure that their contracts with market participants have a strong reliability component. One of the advantages that is provided by the RTO process is independence. The RTO must have no direct financial incentive to favor commercial market transactions that operate to the detriment of reliability.

Control over reliability coordination functions should be consolidated within an RTO. The capability to respond to reliability emergencies must be quick and decisive. Decisions to save the grid cannot be subjected to lengthy negotiations among dispersed agents with potentially conflicting interests. Responsibility to act must be clearly established and the authority to carry out those actions firmly vested in the responsible party. As an emergency approaches, command and control must replace coordination as the decision-making modus operandi. The decentralized system now in place within MISO must give way to consolidation. Operating through 35 separate local reliability control areas, MISO's capability to effectively perform its regional reliability responsibility is seriously compromised. Consistency and clarity regarding how reliability responsibilities are shared among the numerous independent control centers is problematic. Consolidation is desperately needed and we recommend centralization with all reliability responsibility placed under the direct control of MISO. While reducing the number of control areas would help, centralization is by far the more desirable option. Many of the other RTOs and ISOs in the Midwest, Northeast and Mid-Atlantic regions (PJM, New York ISO and the Ontario IMO) operate as centralized reliability control systems. Similarly, we recommend that AEP, currently operating as a satellite within the PJM RTO, be fully integrated and placed under the direct control of an RTO.

Section 2.4.6.6: Transmission Seams

The current RTO configuration resulting from the RTO choices of utilities in the Midwest presents major transmission seams[10] problems. As utilities make and remake their choices based on a number of factors, RTO seams come and go along with those changes. This constant shuffling and reshuffling must stop. The fact is that utilities are connected. A seamless region

[10] Seams refers to the lines dividing the existing RTOs, where power passes from the control of one RTO to another.

will result in better reliability management, because the region would be overseen by one entity. This entity could then make choices based on the entire region, rather than pieces of it. The first step must be getting all of the Midwest utilities into an RTO. The shifting must stop and commitments must be made to stabilize RTO configuration in the Midwest. After that, the RTOs that cover the Midwest can finalize a meaningful joint agreement so that the Midwest region is operated as a seamless area.

Section 2.4.7: Demand Response

Demand response, including distributed generation, must be effectively interwoven into a reliability improvement strategy. Historically, the demand side of the reliability picture has been largely overlooked in favor of the supply side of the equation. Demand response offers great potential to enhance reliability in a cost-effective manner. This opportunity must be aggressively tapped. System load balancing can be accomplished by adjusting either supply or demand. Both must be part of any cost-effective approach. Demand response should include pursuing load control opportunities, such as water heater control and air conditioning cycling equipment, which could greatly improve load-shedding capability. Demand response should also include distributed generation, which offers great value by locating smaller generation in strategic places on the grid that are vulnerable to reliability concerns.

Section 2.5: Conclusions and Recommendations

Thorough examination of the blackout event provides significant insight into reliability problems and concerns evident on August 14th that significantly contributed to triggering the event along with actions that may have resulted in failure to localize the outage and prevent it from cascading over such a widespread area. Our findings include the following:

- There is no evidence from our investigation to suggest that Michigan utilities or transmission operators were the cause of the blackout. All of the transmission line and power plant outages in the two and one-half hours before the two power surges beginning at 4:09 p.m. involved the facilities of FirstEnergy and AEP in Ohio. At the time that the power surges began, the electric system in Michigan was in balance.

- MISO, as the regional reliability coordinator, should have informed affected transmission operators of the disturbances that were occurring in northern Ohio.

- Michigan utilities and transmission companies were not notified of the problems being experienced by FirstEnergy and AEP and received no advance warning of the potential blackout. The first indication in Michigan of an impending emergency occurred at 4:09:27 p.m. when an interconnection in central Michigan exceeded its emergency rating as a result of the first power surge coursing through the State.

- Failure to isolate the FirstEnergy system from neighboring systems permitted the blackout to spread. The key to preventing blackouts from cascading is to take quick and decisive action to localize them. The absence of effective support to contain disturbances from regional coordinators responsible for reliability within the Ohio area where the critical grid disturbances occurred is disturbing. Reliability coordinators responsible include MISO on behalf of FirstEnergy and PJM for AEP. Representatives from all four organizations were involved in discussions regarding the disturbances, yet no one entity was able to see the whole picture and put the pieces of the puzzle together. Among the most obvious improvements that need immediate attention is clarification of reliability responsibilities and how they should be executed. Control room communications and statements by industry grid managers and reliability coordinators in our investigation clearly reveal confusion on this most critical function. Enforcement responsibility, authority, and accountability must be clearly defined and strengthened. Structural changes in how MISO executes its coordination duties must be revised.

- FERC should be provided with the authority to develop and enforce reliability standards. Reliability standards enforcement is inadequate and in urgent need of significant revision. The current system to enforce reliability standards lacks accountability and is generally ineffective. The present enforcement structure relies exclusively upon voluntary standards with no governmental agency responsible for oversight. Reliability standards must become the centerpiece of a comprehensive strategy to improve grid reliability. Reliability standards should be: (1) nationally developed and applied, (2) mandatory, (3) strictly enforced by the FERC, and (4) implemented regionally through the RTOs. FERC should have the responsibility to develop and oversee this process and that agency should be held accountable for the results.

- A single RTO should be established for the Midwest region. Regional grid coordination and management through RTOs in the Midwest is not strong enough and seams between RTOs are causing serious problems that must be addressed. Preventing blackouts from recurring requires a strong and effective regional response. In the Midwest, RTO participation must by mandatory. Cascading outages are an unfortunate byproduct of integrated systems; solutions designed to prevent them require a coordinated response. Coordination is not an option if the nation is committed to seriously addressing reliability; it is a must.

- Consideration should be given to building additional transmission in the region. Curtailments of firm transmission have increased each of the last four years.

- The MISO reliability coordination structure is flawed. Reliability coordination within the MISO system is highly decentralized, with 23 independent transmission companies operating as their own control area operators. MISO, under this fragmented structure, in practice, operates as reliability coordination back-up, with front-line responsibility dispersed among the local reliability control operators. This system is fraught with inconsistency and confusion as to delineation of responsibility to monitor the grid and execute reliability control measures. MISO reliability coordination operates like a loose confederation, significantly undermining MISO's ability to act promptly and decisively.

- Electric grid reliability is in need of support on several levels. There is no quick fix to prevent future blackouts. The solution is complex and must be comprehensive. It involves elements that are interdependent and will encompass both short and long-term remedies. Key to a successful response are four interdependent components which must be substantially expanded and strengthened:

  1) Reliability standards;
  2) Regional grid coordination and management;
  3) Strategic grid investment, where necessary, to cost-effectively expand and upgrade the transmission infrastructure; and
  4) Demand response, including distributed generation.

  To become most effective, these grid improvements should be implemented as a comprehensive package. It would be a mistake to pursue a piecemeal approach.

PART III

UTILITY OPERATIONS

Section 3.1: Michigan Electric Utility Systems

Section 3.1.1: Consumers Energy Company

Consumers Energy Company provides electric service to more than 1.7 million customers and serves 275 cities and villages in 61 counties. Principal cities served are Battle Creek, Bay City, Cadillac, Flint, Grand Rapids, Jackson, Kalamazoo, Midland, Muskegon and Saginaw. The company operates 12 coal-fired and two oil-fired generating plants, 13 hydroelectric plants, a pumped storage generating plant, and several combustion-turbine plants that produce electricity when needed during peak demand periods. The company owns the Palisades nuclear plant. The utility also purchases power from several sources, such as the gas-fired Midland Cogeneration Venture. Major generation facilities include: the J.H. Campbell Generating Complex, J.R. Whiting Plant, the D.E. Karn – J.C. Weadock Generating Complex, the B.C. Cobb Generating Plant, the Palisades Nuclear Plant, Ludington Pumped Storage Plant, and a number of small hydro units.

The J.H. Campbell complex, located on the shore of Lake Michigan between Holland and Grand Haven, is Consumers Energy's largest coal-fired generating complex. Unit 1 began operation in 1962, Unit 2 in 1967 and Unit 3 in 1980. Three turbine-generators produce up to 1,404 megawatts (MW) of electricity.

The Whiting Plant is located on the Lake Erie shoreline of southeastern Michigan. The Whiting Plant produces up to 310 MW of electricity, enough to power a community of 230,000 people. It was built in 1952.

Situated at the mouth of Saginaw Bay, the Karn–Weadock complex generates about one-third of all the electricity produced by Consumers Energy. In 1940 Consumers Energy built the first of what would eventually become eight units on the J.C. Weadock site. Two of those units are still in operation. Between 1959 and 1977, two plants were added: D.E. Karn 1 and 2 and D.E. Karn 3 and 4. The boilers in Weadock and Karn 1 and 2 burn coal; at Karn 3 and 4, they burn natural gas and oil. At peak operation, the plants can produce 2,100 MW of power.

The B.C. Cobb Generating Plant is located on the shores of Muskegon Lake, where its water meets the Muskegon River. The plant's five coal and natural gas units can generate 500 megawatts of electricity.

The Palisades plant, located near South Haven, has been generating electricity since 1971, and represents about 18 percent of Consumers Energy's total electrical capacity. In November 2000, Consumers Energy signed an agreement to become a full partner in Nuclear Management Company (NMC) of Hudson, Wisconsin. As part of the agreement, Consumers Energy transferred responsibility for the operation of Palisades to NMC. Consumers Energy retains ownership of Palisades, the electricity it produces and its spent fuel. The utility also retains the financial obligations for the safe operation, maintenance and decommissioning of the plant.

The Ludington Pumped Storage plant located on Lake Michigan near Ludington can generate 1872 MW of electricity. Customers throughout Michigan use energy generated by the facility. Because its six turbines can begin generating within a few minutes, the Ludington plant can respond quickly to daily, weekly and seasonal changes in energy demands. The Ludington plant operates very simply. At night, when demand is low, the facility's six reversible turbines pump water 363 feet uphill from Lake Michigan. The water is pumped through six large pipes, or "penstocks," to an 842-acre reservoir. During the day, when demand is high, the reservoir releases water to flow downhill through the penstocks. The flowing water turns turbines in the powerhouse to make electricity.

Consumers Energy purchases from small hydroelectric facilities located through out the state that provide 114.9 MW of power. Consumers Energy also owns 345 MW of combustion turbine peakers located throughout the state. The largest group of peakers is at the Thetford facility, which has 192 MW of peakers. There are also 13 MW located at the Campbell facility, 70 MW at Gaylord, 28 MW at Morrow, 16 MW at the Straits, 13 MW at the Weadock facility and 13 MW at the Whiting facility.

Power transmission for Consumers Energy's system is provided by Michigan Electric Transmission Company (METC) – a privately held company. METC acquired Consumers Energy's transmission assets in 2001 and is currently operated out of the Jackson dispatch center. The METC system is interconnected with the American Electric Power system near that utility's Donald C. Cook Nuclear Plant near Bridgman. The transfer capability of this interconnection is rated in 4,000 to 4,500 MW range, depending on the actual configuration of the power system.[11]

Section 3.1.2: The Detroit Edison Company

The Detroit Edison Company, the largest electric utility in the State, generates and distributes electricity to 2.1 million customers in a 7,600 square-mile service territory in Southeastern Michigan. The utility operates 10 base-load generating plants, all within its service area. The company also is co-owner with Consumers Energy of the Ludington Pumped Storage facility. Detroit Edison's system capacity totals nearly 11,000 MW. Coal is used to generate about 85 percent of its total electrical output, with the remainder produced from nuclear fuel, natural gas and solar energy.

The Fermi 2 nuclear plant is located in Monroe County, south of Detroit on the west end of Lake Erie. Fermi is a boiling water reactor with an in-service date of January 1998 and a summer capability of 1,111 MW.

Placed in service in July of 1979, Greenwood is a conventional steam turbine unit that was designed to burn residual oil. It has been converted to dual fuel burners, with the capability to

[11] These numbers are circuit ratings and may not reflect the actual transfer capability of the interconnection at any given time. Actual transfer capabilities could be less.

also burn natural gas. Located at the Greenwood energy center in St. Clair County it has a summer rating of 785 MW.

The Monroe Power Plant is a 3,000 MW facility located south of Detroit in Monroe County. It consists of four coal-fired units, each with a summer capacity rating of 750 MW. Unit 1 went into service June 1971, followed by unit 4 in March 1973, unit 2 in May 1973, and unit 3 in May 1974.

The St. Clair facility, located in county and along the river of the same name, has six active coal-fired units. St. Clair 7 (placed in service in 1969) is the largest with a summer capability of 451 MW, followed by unit 6 (placed in service 1961) with a summer capacity of 321. Units 1 (placed in service in 1953) and 4 (placed in service in 1954) are rated at 158 MW each, while unit 3 (placed in service 1954) is rated at 168 MW, and unit 2 (placed in service in 1953) is rated at 162 MW.

The Belle River Power Plant consists of two coal-fired units, each with capability of 635 MW. Unit 1 was placed in service in August 1984 and unit 2 in July 1985. The plant, with a total capability of 1270 MW, is located near the St. Clair facility.

The Trenton Channel facility located in Wayne County on the Detroit River just north of Detroit has 3 active units. Unit 9, which is coal-fired, is the largest with a summer rating of 535 MW. Units 7 and 8 are each 120 MW coal-fired units.

The River Rouge Facility, located within the city of Detroit, has two active coal-fired units owned by Detroit Edison. Unit 3, placed in service in 1958, has a summer rating of 276 MW. Unit 2, placed in service in 1957, has a rating of 238 MW. Unit 1, placed in service in 1956, is rated at 199 MW. It has been converted to natural gas and transferred to DTE Energy, the parent company of Detroit Edison.

The Harbor Beach plant is located in Huron County near the town of Harbor Beach on Lake Huron. Placed into operation in 1968, the single 103 MW unit burns coal.

Detroit Edison has a total of 1,371 MW of peaking units[12] with 600 MW located at base load generation facilities and 771 located at various other locations throughout the utility's system. Other significant generation[13] owned by companies other than Detroit Edison in its service territory include: CMS Energy's Dearborn Industrial Generation rated at 330 MW, First Energy's Sumpter–Dayton Station rated at 300 MW and DTE Energy Services Dean Plant rated at 300 MW.

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[12] Base load and peaking units are distinguished by cost and operating characteristics. Base load units generally are expensive to build but have low operating costs – they are expected to run a high percentage of the time to take advantage of the low variable cost and spread the high fixed cost over a larger volume of output. Conversely, peaking units are relatively cheap to build but have high operating costs -- they are expected to operate only a small percentage of the time (10% or less).

[13] A map of merchant plants in Michigan is available in PDF format from the State Utility Forecasting Group at Purdue University. See https://engineering.purdue.edu/IIES/SUFG/MAPS/index_html.

International Transmission Company (ITC) owns and operates the transmission lines associated with the Detroit Edison system. It is made up of transmission facilities formerly originally owned by Detroit Edison, which were sold to an independent transmission company in 2002. Detroit Edison currently switches, repairs and maintains the ITC transmission assets under contract. This arrangement will continue for one year. Switching is controlled from Detroit Edison's Systems Operation Center.

Most of the control area operation in Michigan is done by the Michigan Electric Coordinated Systems (MECS) at the old Ann Arbor Power Pool. MECS is comprised of ITC and METC, the two independent companies that operate the Michigan grid.

The Detroit Edison/ITC system has 345 kilo-Volt (kV) interconnection with FirstEnergy at Allen Junction–Majestic–Monroe, Lemoyne–Majestic and Bayshore–Monroe. All of the interconnections are in the southeast corner of Michigan. The Detroit Edison/ITC system is interconnected with Hydro One in Ontario at the 345 kV level through two interconnections at Lambton–St. Clair near Detroit Edison's St. Clair power plant. The total transfer capability with FirstEnergy is 3,380 MW, and 2,400 MW with Hydro One.

The Consumers Energy/METC system has four 345 kV interconnects with the Detroit Edison/ITC system: (1) Majestic–Battle Creek–Onedia, (2) Majestic–Tompkins, (3) Thetford–Jewell, and (4) Pontiac–Hampton. These interconnections have a combined continuous rating of 3,000-3,500 MW depending on the power flow and a short term rating in the 4,000-4,500 MW range.

Section 3.1.3: American Electric Power

American Electric Power (AEP) serves customers in the lower western portion of the state. Its major generation facility within Michigan is the Donald C. Cook Nuclear Power Plant, located on the shores of Lake Michigan near Bridgman. The 1,020 MW Unit 1 went into commercial operation in 1975, while the 1,090 MW Unit 2 was completed in 1978. AEP's 765 kV transmission system is interconnected to the Consumers Energy/METC system near the Donald C. Cook plant.

Section 3.1.4: Lansing Board of Water and Light

The Lansing Board of Water and Light (BWL) is a municipal utility, owned by the citizens of Lansing. The BWL is the third largest electric utility in the state serving 98,000 customers and the largest municipally-owned utility in Michigan. The BWL has two generating stations: Erickson (located west of Lansing) and Eckert (located near the center of the city). The Erickson Station was completed in 1973 and contains a single coal-fired unit capable of producing 159 MW. It was recently rated one of the most efficient plants of its size in the United States.

Eckert Station Located near downtown Lansing was constructed in the early 1920's and has undergone several rebuilding and expansion projects. The Eckert Station includes six electric generating units ranging from 41 to 77 MW. The six units are capable of generating a total of 351 MW.

Through a membership in the Michigan Public Power Agency (MPPA), the BWL also receives 146 MW of electricity from the Belle River Plant operated by Detroit Edison. The BWL is interconnected with Consumers Energy in two locations.

Section 3.2: Emergency Procedures

Section 3.2.1: Load Management

Three load management mechanisms are available to interrupt electric load when generation supply, system voltage, or system frequency become deficient: (1) Rotating Load Management (RLM), (2) Remote Load Shed (RLS), and (3) Automatic System Security.

On the Consumers Energy system the RLM approach utilizes rotating blackouts involving Supervisory Control and Data Acquisition (SCADA) control of substation circuit breakers. Detroit Edison uses a manual system to accomplish the same function. RLM is designed to interrupt firm load in the event of a generation shortage or when a widespread transmission system emergency exists. The RLM system is intended to be implemented prior to initiation of Automatic System Security.

For example, on the Consumers Energy system there are fourteen RLM load segments, each with an average load of 89 MW. Twelve of the segments can be implemented via use of SCADA control of substation circuit breakers. Each segment consists of an average 110 MW of load from each of three System Control Center areas – South, West and East. The two remaining segments are manual industrial segments that require operator intervention at the substation/customer site to interrupt load. The Detroit Edison system operates in a similar manner, except the system uses a manual control process.
No interruptions of hospitals with surgical facilities are included in the plan.

Depending upon the electric system requirements, any segment or part of a segment can be interrupted by opening selected 23 kV, 46 kV, and 138 kV circuit breakers via SCADA (on the Consumers Energy system), certain customer substation equipment or customer switchgear equipment. Designated customer substations, sub-transmission and transmission lines will be interrupted for two hours. Customers would be interrupted for two to four hours (or longer if equipment failure or system malfunction occurs). If required, the next RLM segment will be interrupted. Restoration of the prior RLM segment will commence via SCADA on most of Consumers Energy's system and manual intervention Detroit Edison's system.

Consumers Energy and Detroit Edison have the capability to implement RLS to drop load during isolated transmission system problems, which do not require system-wide operating intervention or RLM capabilities. Implementation of RLS is normally the first step after an Emergency Condition has been declared.

On the Consumers Energy system, thirty-three load segments, ranging from 30 to 271 MW, have been identified for RLS purposes via SCADA control of substation circuit breakers. The priority of the RLS segments is based on the nature and location of the transmission system emergency. Depending upon the electric system requirements, any segment can be dropped by opening 23 kV and 46kV circuit breakers via SCADA. Designated sub-transmission lines will be dropped and remain de-energized until the transmission system deficiency has been mitigated.

Both Consumers Energy and Detroit Edison have Automatic System Security under frequency relays installed on selected transmission substation circuit breakers and distribution substation circuit reclosers. These relays will trip and block reclosing of the circuit breakers and reclosers if the system frequency declines below preset values. The intent of this system is to prevent widespread electric system disruption and ultimately system-wide blackout should manual intervention (RLM or RLS) not be implemented quickly enough to stop frequency decay.

On the Detroit Edison system, automatic load shedding did operate as designed at the beginning of the blackout. During the event of August 14, no manual load shedding was implemented due to the absence of advance warning. On August 14, prior to the blackout, both systems were in normal operating condition with all safety devices in service and functional.

Section 3.2.2: System Protection

The transmission and distribution systems are considered to be stable when voltage, frequency and thermal loading are within normal operating ranges without dramatic variances. In Michigan, the system is designed to withstand the loss of one or more key components.

Key transmission lines and distribution circuits are monitored for excessive current. If an overload condition is detected, the protective relaying or other equipment will interrupt the circuit to prevent damage. The main purpose of this electrical protective equipment is to protect the physical components and maintain electrical integrity of a power system against faults (short circuits).

System frequency is usually maintained at 60 Hertz,[14] but power shortage or oversupply conditions can affect this frequency. For example, if there is an undersupply of power, frequency will drop. This can cause damage to customer or utility equipment. Electric utilities maintain protective relaying systems to monitor for these conditions and to isolate the source.

When reactive power is under or over supplied, voltage will decrease or increase. Either of these conditions can damage critical equipment owned by the utility or the customer. Once again, protective relaying is required to prevent damage.

Protection schemes are designed to rapidly isolate a failed or faulted component or segment of the power system to minimize both its effect on the rest of the power system and damage to the affected component. This allows the remainder of the system to continue to operate normally.

[14] Hertz is a unit of frequency equal to one cycle per second.

In some cases, lightning strikes for example, faulted line segments are automatically restored to service.

The level of sophistication, redundancy and type of protection equipment used depends on the voltage level of the system on which it is installed. Most protective relays monitor current, voltage, and combinations of these, to determine if an abnormal condition exists. The protection engineer sets the relays to respond to the conditions predicted in system models. Relay schemes are generally divided into phase protection and ground protection. The phase schemes detect when conductors for different phases contact each other. Ground protection schemes detect faults to earth ground, such as lightning. These relays schemes are typically located in the substations and trip the appropriate circuit breakers at line terminations.

On 345 kV transmission systems, most protective schemes are communication based. This means that the protective relays at each end of the line "communicate" with each other via power line carrier, audio tone (phone lines), or fiber optics, in order to determine if a fault exists. This provides complete coverage for high speed clearing of the entire line. METC and ITC systems typically have three levels of redundancy: two primary systems that rely on relay communication and a backup system that operates independently at each end.

On 138 kV transmission systems, some communication-based protection exists where it is required for grid stability or relay coordination. In general, the remaining relay protection is impedance-based, effectively measuring an electrical "distance" down the line. If a fault lowers the impedance to a value that falls within its zone of protection, the relay operates. Most schemes have three zones of protection, operating at different current levels and time delays in order to assure that only the faulted segment is isolated. Zones overlap to provide varying degrees of redundancy.

On the 46 kV high-voltage distribution systems, the relay protection is less sophisticated because less protection is required. Most of the phase fault protection consists of coordinated time-over-current elements that are controlled by impedance-based elements that determine directionality of the fault current. If current flow indicates that a fault could be located downstream, the relay operates. This operation occurs after a specified time delay based on the magnitude of the current flow. The time delay allows the protective devices electrically closest to the faulted equipment to operate first.

The North American Electric Reliability Council (NERC) states that a security coordinator must ensure the integration of reliability practices within an interconnection and market interface practices among regions. The security coordinator is responsible for recognizing alert conditions and providing notification to control areas and transmission providers. Alert conditions include cases where energy requirements cannot be met or resources cannot be scheduled. Transmission Load Relief (TLR) is a mechanism for a security coordinator to curtail or re-dispatch scheduled transactions to keep the use of the grid within its operating limits. The security coordinator for the Consumers Energy/METC system and the Detroit Edison/ITC system is the Midwest Independent System Operator (MISO).

Section 3.2.3: Individual Generating Units

Individual generators are protected from damage by protective relays. These relay systems sense conditions[15] and isolate the generator from the system if any of the conditions exist or are out of range. Individual relays are on each unit. Also, additional multifunction digital relays are on many units. The multifunction relays have several protective functions incorporated into one device, some of these protective functions duplicate the features of individual relays, but others provide alarms only.

When a generating unit is in the process of being shutdown during a planned outage, steam flow from the boiler to the turbine is decreased through control valves to gradually reduce the electrical load on the unit. This is coordinated with other generation and transmission organizations to ensure system stability. Once the unit's load has been reduced, the main unit breaker is opened. Remaining operating plants increase outputs slightly to satisfy the real and reactive load being served by the unit being shutdown. Numerous procedures are then performed on the off-line unit to prevent damage from residual thermal effects or other physical conditions. This gradual unloading process cannot be followed during an emergency shutdown. In such a case, the main unit breaker trips with the control valves between the boiler and turbine closing. The dramatically increased steam pressure in the turbine and boiler are relieved through equipment and procedures designed to protect personnel and equipment. Returning a plant to service after an emergency shutdown requires time-consuming efforts due to the possibility of damage resulting from the rapid shut down.

Under normal operation, the pressure of the steam generated in boilers in power plants is proportional to the load the plants are serving. When electrical load is suddenly removed from the electrical generator, the steam valves, which feed steam from the boiler to the turbine, close to bring the plant to a rapid but controlled shutdown. During this process, the pressure in the low-pressure turbine may increase suddenly. Rupture discs are designed to relieve this pressure. They are incorporated in power plants in the low-pressure section of the steam turbine to prevent injury to personnel or damage to equipment. If the rupture discs do not perform this function, the turbine generator could be damaged due to an over-speed condition, or the steam turbine housing could rupture. Either of these situations could injure workers and require months or years to repair. Once a rupture disc has operated, it must be replaced before a unit can be returned to service.

When a power plant shuts down, residual thermal effects can distort the Machine Turbine Generator (MTG) shaft or damage its bearings. A sequence of operations must be carefully followed to prevent any of these critical elements of the system from being damaged. Repair of these elements can take months or years. For example, the MTG shaft must continue to turn after steam ceases to enter the turbine – if this motion does not continue, the hot shaft could warp under its own weight.

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[15] Examples include: phase differential, loss-of-field, negative sequence, volts per hertz, stator ground over-current, reverse power, under-frequency, inadvertent energization, stator ground over-voltage, phase distance, generator field ground and generator field over-excitation

Section 3.3: The Blackout

The events leading up to the blackout are discussed in Part I. The initial impact appeared on the Michigan system at 4:09 p.m. on August 14, 2003, as a large load in northern Ohio. This load was initially balanced by power coming into Michigan on the METC system through its interconnection with the AEP system in southwestern Michigan and flowing through the ITC system to FirstEnergy. As described in Section 1.3.1, a rapid series of cascading failures caused violent power surges to flow through Michigan, ultimately causing the interconnects to trip between Consumers Energy, Detroit Edison and surrounding utilities. Some of these interconnections flows are shown in Charts 3.1 and 3.2.

Chart 3.1

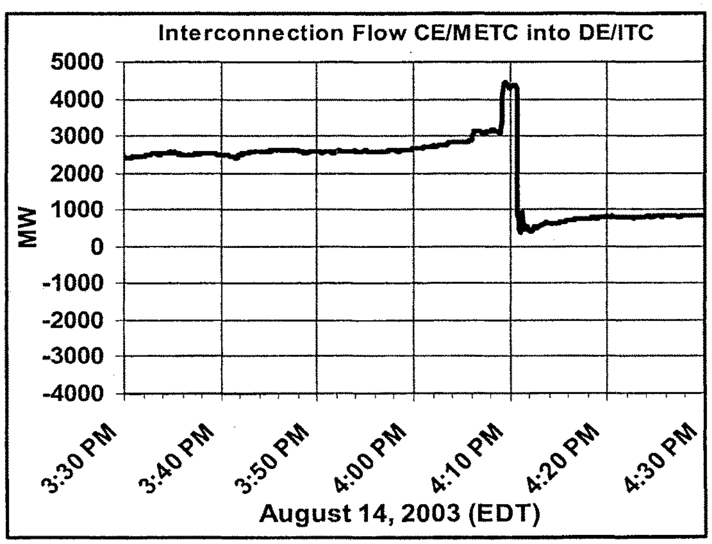
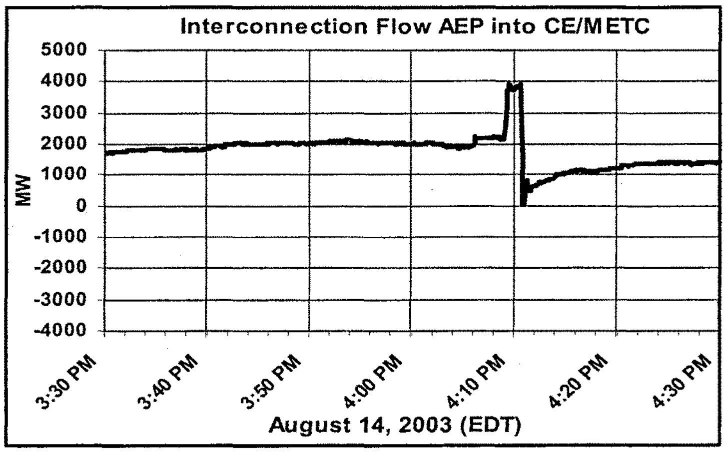


Chart 3.2



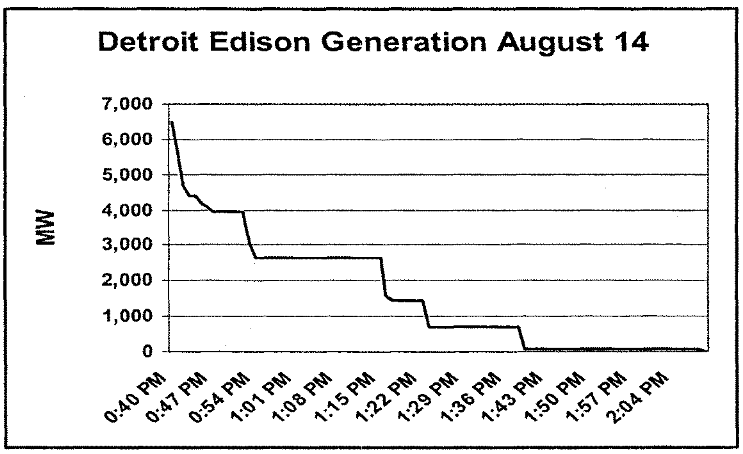
Both Consumers Energy and Detroit Edison report they had no knowledge of the problem developing between FirstEnergy and AEP. In addition, they had no advance knowledge regarding the impending event. The short lead-time (seconds rather minutes) prior to this event on the Michigan system did not allow for human intervention by any entity connected to the system. All actions taken were initiated by automatic switching equipment under the direction of the logic embedded in the systems that control interconnection relays. The protective equipment viewed the increase in load and the general voltage collapse as a fault to ground. Michigan power providers received no advance warning to enable them to protect their customers from the outage.

During the initial seconds of the event, as experienced in Michigan, the Consumers Energy/METC system, which had been transferring about 2,000 MW of power into the Detroit Edison/ITC area prior to the event, separated from the Detroit Edison/ITC system under the additional load placed on it by the FirstEnergy load in Ohio. The load across the east-west interconnections exceeded 4,200 MW on an interconnection with a short term rating of about 4,000-4,500 MW and a 24 hour rating of 3,000-3,500 MW. See Chart 3.1. During this same period the system was experiencing a general collapse in voltage – for example, the voltage at the ITC Bayshore 345 kV interconnection with FirstEnergy dropped to below 305 kV and Detroit Edison 's voltage at its Pontiac Station dropped to 78% of the normal voltage. The protective equipment was designed to interpret such a voltage collapse as a fault to ground.

During the initial phase of the event Consumers Energy's Campbell unit #3, the MCV power facility, the Jackson-based Kinder Morgan facility and most of Detroit Edison's major units were tripped off line by their automatic protection systems. See Charts 3.3, 3.5, and 3.6 for details. In some cases the reactive load requirements placed on generation units exceeded the maximum capabilities by over 300%.

The pre-event loadings coupled with the increased requirements to support FirstEnergy through ITC simply overloaded the Michigan systems and caused the interconnections to open isolating the Detroit Edison system from the Consumers Energy generation and the Ludington Pumped Storage Facility. Consumers Energy was able to continue serving most of its customers through: (1) its own generating units, which, except for Campbell # 3 and the three Whiting Units, stayed on line; (2) AEP power, including power that had been flowing through METC to ITC/Detroit Edison; and (3) Detroit Edison's share of the Ludington Pumped Storage Facility. Some Consumers Energy load was lost in the Flint area during the disconnection of METC from ITC and several southern counties lost power due to the outage of the Whiting Power Plant.

Chart 3.3



The August 14 event heavily impacted the Michigan electric power systems from a reactive power standpoint. Reactive power must be present at sufficient levels to maintain voltage. Without adequate reactive power support, voltage levels fall and the system becomes unstable. The reactive power component cannot be transported long distances as can the active power component and must be produced fairly close to the actual load either by spinning generators or capacitor banks.

At 3:30 p.m. on August 14 (prior to the blackout), the Michigan generation was supplying about 300 megavars (MVAR) to FirstEnergy over the ITC/FirstEnergy interconnection. The MVAR required to support FirstEnergy increased slowly over the 30 minute period preceding the event until it reached just over 400 MVAR at 4:06 p.m. At that time, it jumped to nearly 700 MVAR, where it remained until the METC and the ITC systems separated at 4:10 p.m. After the separation the MVAR flow into FirstEnergy from ITC was near zero.

During this period, the METC system was supplying roughly 200 MVAR into the AEP system in support of the 2,000 MW of power that was being transferred into Michigan over the METC/AEP interconnection. The Consumers Energy/METC system was also supplying about 200 MVAR into the Detroit Edison/ITC system just prior to the event. As the event unfolded, the MVAR transfer into the Detroit Edison/ITC system increased to nearly 300 MVAR at about 4:10 p.m., then reversed and became a 700 MVAR draw from the DE/ITC system just as the event occurred.

Michigan based generating units experienced an extremely large MVAR draw just prior to the event and during the initial phase of the event. Consumers Energy reports that all of the connected generation experienced MVAR requirements beyond their normal capabilities. Generating units are not capable of supporting MVAR requirements at elevated levels for a lengthy time without sustaining serious damage. Chart 3.4 displays the MVAR variation experienced by CE's Campbell unit 3 during the event.

Chart 3.4

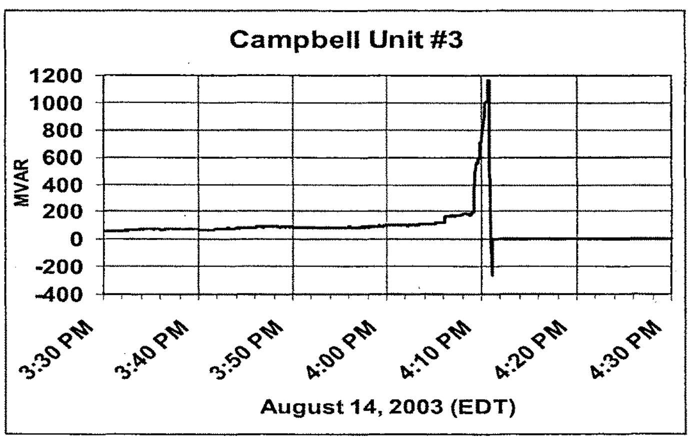


Chart 3.5

Consumers Energy Generation Status Before and After the Event						
Plant	Unit	Rating	Load @ 16:00	Load @ 16:15	Trip Time	Cause of Trip
Allegan Hydro		2.5	0.87	0.34	16:15:00	Undervoltage
Campbell	1	260	265	262		
Campbell	2	355	350	347		
Campbell	3	820	812	0	16:10:42	Turbine thrust bearing
Cobb	4	156	152	145		
Cobb	5	156	158	158		
Cooke Hydro		7.5	3	3		
Croton Hydro		8.4	2	2		
Five Channel Hydro		6.4	3	1		
Foote Hydro		9.9	2	2		
Gaylord	2	14	13	13		
Gaylord	4	14	12	12		
Hardy Hydro		32.4	10	10		
Hodenpyl Hydro		18.4	3	3		
Karn	1	255	212	208		
Karn	2	256	196	0	16:13:50	Boiler trip
Karn	3	511	633	632		
Karn	4	638	606	605		
Loud Hydro		638	2	2		
Ludington	2	312	0	253		
Ludington	3	312	286	303		
Ludington	4	312	325	306		
Ludington	5	312	283	308		
Ludington	6	312	285	290		
Mio Hydro		4.4	1	1		
Palisades		767	762	763		
Rogers Hydro		6	1	1		
Straits		16	14	14		
Tippy Hydro		21	5	5		
Weadock	7	151	153	146		
Weadock	8	151	154	146		
Whiting	1	102	96	0	16:10:44	Generator Protective Relaying
Whiting	2	102	102	0	16:10:44	Generator Protective Relaying
Whiting	3	122	125	0	16:10:59	Generator Protective Relaying

The large MVAR draw on the Michigan system signifies a voltage collapse somewhere on the interconnected system. A further complication of the situation occurs as the MW draw across the Michigan system jumped to over 3,000 MW and subsequently above 4,200 MW. This power transfer across Michigan used up a large portion of the available MVAR support to support the transfer. Unable to maintain the required MVAR support the Michigan systems entered a voltage collapse situation that precipitated the tripping of the generation that Detroit Edison had on-line. With the interconnection with Consumers Energy/METC system open and with almost all of its generation tripped off-line, Detroit Edison was unable to support its internal load.

Chart 3.6

Detroit Edison Generation Status Before and After the Event						
Plant	Unit	Rating	Load @ 16:00	Load @ 16:15	Trip Time	Cause of Trip
Greenwood	1	785	299	0	16:10:40	Generator Protective Relaying
St. Clair	7	450	144	0	16:10:41	Generator Protective Relaying
Belle River	1	625	609	0	16:10:41	Generator Protective Relaying
Connors Creek	MTG 15	135	137	0	16:10:41	Generator Protective Relaying
Greenwood	11--1	75	76	0	16:10:42	Generator Protective Relaying
Greenwood	11--2	75	77	0	16:10:42	Generator Protective Relaying
Greenwood	12--1	75	75	0	16:10:42	Generator Protective Relaying
Trenton Channel	7A	110	95	0	16:10:42	Generator Protective Relaying
Trenton Channel	8	100	105	0	16:10:42	Generator Protective Relaying
Trenton Channel	9	520	489	0	16:10:42	Generator Protective Relaying
St. Clair	6	321	285	0	16:10:43	Generator Protective Relaying
Belle River	12--1	75	75	0	16:10:45	345KV Breakers Tripped
Belle River	12--2	75	74	0	16:10:45	345KV Breakers Tripped
Belle River	13--1	75	75	0	16:10:45	345KV Breakers Tripped
Harbor Beach	1	103	83	0	16:10:46	Manual Trip by Unit Super. Ope
Delray	11--1	70	62	0	16:10:47	345KV Breakers Tripped
Delray	12--1	70	62	0	16:10:47	345KV Breakers Tripped
St. Clair	4	158	140	0	16:10:53	LP Turbine Overspeed
Monroe	4	775	767	0	16:10:53	Generator Protective Relaying
River Rouge	3	272	270	0	16:10:54	Generator Protective Relaying
St. Clair	2	162	138	0	16:11:04	Data Not Available
Fermi	2	1111	1094	0	16:11:16	Generator Protective Relaying
Monroe	2	750	109	0	18:01:17	Generator Protective Relaying
Monroe	3	750	733	0	16:11:23	Generator Protective Relaying
Belle River	2	635	636	0	16:11:39	Generator Protective Relaying
Connors Creek	MTG 16	80	73	0	16:12:09	Manual Trip by Unit Super. Ope
Belle River	DG 11--1	2.75	2.25	0	18:07:35	N/A
Belle River	DG 11--2	2.75	2.25	0	18:07:37	N/A
Belle River	DG 11--3	2.75	2.25	0	18:07:39	N/A
Belle River	DG 11--4	2.75	2.25	0	18:07:41	N/A

Section 3.4: Review and Analysis of Actions Taken

The events that occurred outside of the State that preceded the outage were beyond the view of the power system operators within Michigan. This and the lack of advance warning from MISO, First Energy, AEP, or any other organization, prevented the Michigan electric system operators from taking manual action to protect customers from the impending outage. Even if the Michigan electric system operators had full knowledge of the generation and transmission line outages unfolding between FirstEnergy and AEP, actions open to them might have presented a significant risk to the stability of the Michigan system. Isolating the Michigan system from its interconnections with outside utilities would have been difficult at best and the results uncertain because Detroit Edison was importing about 2,900 MW through the METC/ITC system from the METC interconnect with AEP.

If Michigan operators had full knowledge of the events occurring elsewhere, it appears that approachs other than full isolation may have been available to prevent or at least significantly reduce the pending power surges. In order to prevent the power surge from coming through Michigan, the ITC/FirstEnergy interconnect could have been opened prior to the event. If it is not done before the event, once the interconnect is heavily loaded, opening it would likely have forced Detroit Edison generating units off-line due to turbine over-speed from the sudden loss of load. This could have caused a power outage on the Detroit Edison system. In any case, the lack of information from other systems prevented Michigan operators from exercising or considering this option.

The other course of action that may have prevented the outage in the Detroit Edison service area would have involved unloading the interconnections between the Consumers Energy/METC system and the Detroit Edison/ITC system in advance of the event. An unloaded interconnection may have weathered the coming storm causing the interconnections between ITC and FirstEnergy to open sparing the Detroit Edison system from a full blackout. If Detroit Edison or ITC had received advance notice of the problems experienced elsewhere, they may have been able to increase generation levels within the Detroit Edison territory, thereby unloading the ties with the Consumers Energy/METC system. If Michigan companies had been provided enough advance notice of the events[16] occurring between FirstEnergy and AEP, such action may have reduced or eliminated the impact on Detroit Edison and Consumers Energy customers.

Detroit Edison generation on-line at the time of the blackout had the capability to provide an additional 1,600 MW of power. If Detroit Edison had known of the problems being experienced elsewhere, it could have ramped up its internal generation prior to the event to full power levels in the time period between the FirstEnergy Hanna-Juniper 345 kV trip at 3:32 p.m. (this was the second 345 kV line to trip within the FirstEnergy system, the first was Chamberlain-Harding at 3:06 p.m. EDT) and 4:09 p.m. This would have reduced the transfer across its interconnection with METC by 1,600 MW to approximately 1,300 MW. With the transfer level in this range a Detroit Edison system blackout could probably have been avoided.

Detroit Edison could not exercise this option because the key information regarding the impending system disturbance was not shared beyond FirstEnergy, AEP and MISO. Failure to share key reliability information with Detroit Edison or ITC also prevented ITC from considering the option of opening its interconnections with FirstEnergy, or at least opening two of the three to allow automatic interruption of the remaining connection prior to the opening of the METC/ITC interconnections.

It appears based on the results of this investigation that the protection systems located within Michigan worked as designed. The Detroit Edison/ITC system had too much power flowing into its system to survive a separation from the Consumers Energy/METC system without major generating units tripping off-line. The Consumers Energy/METC system was able to separate a major portion of its system from the problem. The fact that there was no major damage either to transmission and associated equipment or to generating units and their associated equipment demonstrates that the automatic protection equipment worked as designed. If this equipment had

[16] Four organizations, MISO, PJM, FirstEnergy, and AEP, had information about these events. Any of them could have, and should have, provided the information they had to other affected entities.

not worked as designed, there would likely have been major damage to facilities that could have taken weeks or even months to replace or repair.

Section 3.5: Recovery

Section 3.5.1: Consumers Energy

Restoration efforts were undertaken immediately following the event. Consumers Energy issued an emergency page to notify departments within its Transmission & Distribution organization that a significant system disturbance had taken place and requested that leadership personnel report to the nearest System Control Center. Local headquarters in the affected areas were also instructed to remain open. A conference call was established at 5:15 p.m. to determine initial actions. Subsequent calls were held every two to three hours thereafter. Independent conference calls were also held with METC on a similar schedule.

Personnel in the Merchant Operations Center assessed generation status and established communications with operations centers within Michigan and nearby systems. Management from Fuels & Power Transactions and Nuclear, Fossil and Hydro Operations organizations arrived by 4:30 p.m. to monitor the situation and direct restoration efforts from the supply side. Merchant Operations personnel opened communication with DTE merchant personnel as well as transmission operators to assess the extent of the disruption on supply resources.

On the Consumers Energy/METC system there were significant generator outages, numerous line outages, and two areas were without power. Generation outages included Midland Cogeneration Venture (1,240 MW) in Midland, Karn 2 (260 MW) in Bay City, Campbell 3 (820 MW) in Port Sheldon, and Whiting 1-3 (330 MW) in Monroe. Line outages included two 345 kV ties and two 138 kV ties between METC and the Detroit Edison/ITC system, two 138 kV ties between METC and Lansing BWL, one 138 kV tie between METC and Northern Indiana Public Service Company (NIPSCo), and a multitude of 138 kV and 46 kV lines in the southeastern portion of the state. Additionally, there was one 46 kV line in the Flint area that was out of service and numerous distribution circuits locked out. The two major areas without power were the Lansing BWL and the southeast corner of Consumers Energy's service territory (geographically enclosed predominately by I-94 to the north and M-66 to the west).

Immediately following the event, Consumers Energy started generation in response to the loss of units. Consumers Energy believed at that time it was under-generating, but interconnection frequency continued to be above 60 Hertz, which would generally be an indication of over-generation. In consultation with transmission operators, Consumers Energy maintained its generation level until the status of the system, both in Michigan and in neighboring areas, could be assessed. Between 5:00 p.m. and 7:00 p.m. power output from the Ludington Pumped Storage facility was reduced in order to moderate high frequency levels and manage available stored water for later restoration needs of Detroit Edison. Consumers Energy also obtained additional supplies of electricity from in-state independent power producers and AEP.

Restoration efforts followed black start[17] procedures. Efforts began with an assessment of the 138 kV and 46 kV breakers that were open. The open breakers were plotted on a geographic map of the electric system in order to determine the boundaries of the affected areas. Having defined the affected area, System Control Centers began the process of opening up all breakers contained within the affected area via SCADA and field personnel.

Consumers Energy's Lead System Control established communication with the Electric Sourcing and Trading group to keep apprised of generation status. The Lead System Control also established communication with the Michigan Electric Power Coordination Center, ITC and MISO to keep apprised on issues pertaining to the transmission system and its interconnections with neighboring utilities.

Consumers Energy's merchant group maintained communication with its Detroit Edison counterpart, as well as other control centers. Consumers Energy agreed to fill Ludington Pumped Storage overnight for both itself and for Detroit Edison to prepare for restoration efforts the next day.

The return of generation at the Whiting facility and the restarting of generators at Kinder Morgan power plant were a top priority. These units provide both local power supply and area voltage support. Also, Consumers Energy believed that the automatic relays (which are designed to isolate distribution circuits for sustained periods of under-frequency operation) had tripped and that personnel would need to be dispatched to reset these relays and energize the tripped circuits. Consumers Energy personnel from the western and central portion of Michigan were dispatched to the affected area to aid in resetting the relays.

As of 5:15 p.m., all breakers within the affected area were opened, and the process of restoring the 138 kV system was undertaken. This included service to Whiting Substation, which provided station power for restarting Whiting Generation. The 138 kV system, with the exception of the ties with ITC and NIPSCo, was restored by 7:25 p.m. During restoration of the 138 kV system some 46 kV and 138 kV connected load was also restored. At that time System Control began energizing the remaining 46 kV lines and restoring customers to service. At this point, the system was net generation deficient. Therefore, restoration of customers progressed at a pace relatively equal to the rate at which generation became available.

As generation, particularly the Kinder Morgan power plant, began ramping toward full output, the 46 kV system was restored in the affected area. By 10:05 p.m. on August 14 all 46 kV lines had been energized and all load was returned to service. Automatic relays were checked and it was determined that the relays had not tripped as initially believed. The field personnel dispatched from surrounding areas were returned to their respective headquarters.

The ties between METC and Lansing BWL remained closed from the METC end throughout the event. At 7:45 p.m. on Thursday, August 14, Lansing BWL closed their end of the ties in agreement with METC.

[17] See Section 3.5.2 for an explanation of black start procedures.

According to Consumers Energy's Outage Management System, up to 118,400 customers were out of service during the 4:00 p.m. through 10:00 p.m. timeframe on August 14th.

A restart of Campbell 3 was attempted at 7:44 p.m. but was aborted when the unit experienced water hammer two minutes after turning on steam. This damaged a number of piping hangers in the plant, which required repair, delaying the units return to service. As information on Campbell 3's status and repair time became known, and with the uncertain status of the transmission system, Consumers Energy issued a request that customers continue to conserve electrical use into Friday, August 15.

With the southeastern portion of the Consumers Energy/METC system returned to a normal situation, except for the Whiting Generation and the 138 kV ties to ITC and NIPSCo, seventy-five percent of the power supply to the affected area was coming from the Kinder Morgan power plant and transmitted on the Leoni–Beecher (Jackson to Adrian) and Leoni–Parr Road–Whiting (Jackson to Monroe) 138 kV Lines. The remaining twenty-five percent of the power supply was from the Verona Substation in Battle Creek and was transmitted on the Verona–Batavia 138 kV Line (Battle Creek to Coldwater). These three 138 kV lines, now critical to supply power to the recently restored area, were heavily loaded but within applicable continuous capability limits.

At 10:30 p.m. the Leoni–Beecher 138 kV Line tripped and did not re-close at Beecher due to loss of station power. This resulted in large flows on the remaining two critical 138 kV lines, causing them to open at their source ends. The system within the subject geographic area was then in nearly the same state as it was following the primary 4:09 p.m. outage.[18] Immediately, a similar restoration plan to the primary outage was executed. The 138 kV system was restored by 12:55 a.m. Friday, and the 46 kV system along with all of the connected customers was restored by 1:35 a.m. Friday.

During restoration efforts field personnel were dispatched to patrol the Leoni–Beecher 138 kV Line. Relays protecting this line were remotely interrogated and a suspected fault location was identified. This information was passed on to the field crews as a place to start their patrol. Due to darkness and foggy/hazy conditions, the source of the fault was not located. When that line was returned to service at 11:00 p.m., it was given a derated capability equal to its historically highest sustained power flow in order to avoid further trips or failures.

According to Consumers Energy's Outage Management System, up to 70,100 customers were out of service during the 10:00 p.m. August 14th through 6:00 a.m. August 15th timeframe.

The morning weather forecast for August 15 was reviewed and with the capacity available at that time, Consumers Energy was expected to be short of ECAR operating reserve requirements. Internal company load reductions were ordered, and the public was asked to conserve all day. Specific customers were contacted to request voluntary curtailments and an estimated 400 MW of reduction was obtained. At 12:45 p.m., Detroit Edison gave Consumers Energy permission to use its unused Ludington capacity to meet load. By 4:00 p.m. on August 15, rainstorms occurring across the Consumers Energy service area reduced load, which allowed the widespread general public conservation to be discontinued.

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[18] However the night-time load was considerably less then the afternoon load.

Several reliability concerns were handled by Consumers Energy personnel over the next two days. These included problems in adhering to the derated capability of the Leoni–Beecher line, the clearance status of 138 kV lines located within the affected area, and large power flows between the METC and ITC systems. In addition, continued hot weather, unit outages caused by the event, and uncertain power availability to supplement Consumers Energy's own internal generation led to a forecast of a deficiency in Consumers Energy's operating reserve.

Adhering to the derated capability of the Leoni–Beecher line resulted in Consumers Energy's System Control curtailing load. As loads came up on Friday morning, power flow on the Leoni–Beecher line began to exceed the derated capability established the previous night, risking a line trip again and potentially another outage. Two actions were taken to adhere to the derated capability. All customers in the affected area were asked to curtail power usage and load management procedures were put into place. This resulted in a forced outage of industrial customers in that area and a reduction of approximately 16 MW of load. Additionally the Raisin, Tecumseh Products, La Salle, and Erie 46 kV lines were forced out of service. This resulted in a reduction of approximately 40 MW of load. According to Consumers Energy's Outage Management System, up to 17,500 customers were out of service during the 7:00 a.m. through noon timeframe on August 15th.

With the return of the first Whiting generator at 9:30 a.m. on August 15, the 46 kV lines were restored to service. However, continued restriction of the related large customers was maintained since loading on the Leoni–Beecher line remained at approximately ninety percent of the derated capability. This restriction was imposed until generation at Whiting stabilized on Saturday and all related industrial customer load restrictions were lifted.

All 138 kV lines contained within the affected area, especially the 138 kV lines deemed critical, were patrolled on Friday, August 15 in an effort to avoid a repeat of the Leoni–Beecher line trip. After all items identified as possible concerns were resolved, the remaining ties between Consumers Energy/METC system and Detroit Edison/ITC were closed by 1:05 p.m. on Saturday, August 16.

The final concern was possible separation between the Consumers Energy/METC and Detroit Edison/ITC systems due to any one of three single-contingencies involving tie lines between the two systems on Saturday.[19] With Detroit Edison being generation deficient, it was dependent upon the Consumers Energy/METC system interface for power supply, particularly in the thumb area of Michigan. With power flows between the two systems reaching the 3,000 MW range, analysis indicated a single contingency would load other ties between the Consumers Energy/METC system and the Detroit Edison/ITC system above emergency capabilities. This could start a cascading outage resulting in separation between the METC and ITC systems. A number of items were implemented to prevent this from occurring. On the daily morning conference call with METC these concerns were discussed and patrols were ordered for the METC portion of the tie lines identified by the analysis. MECS and ITC were notified of the

[19] The term "single-contingency" is used in the industry to indicate a situation resulting from the outage of a single unit or transmission line currently in operation. The concept is to plan for operation of the system in a manner that will allow it to continue to function in the event that something unexpected happens.

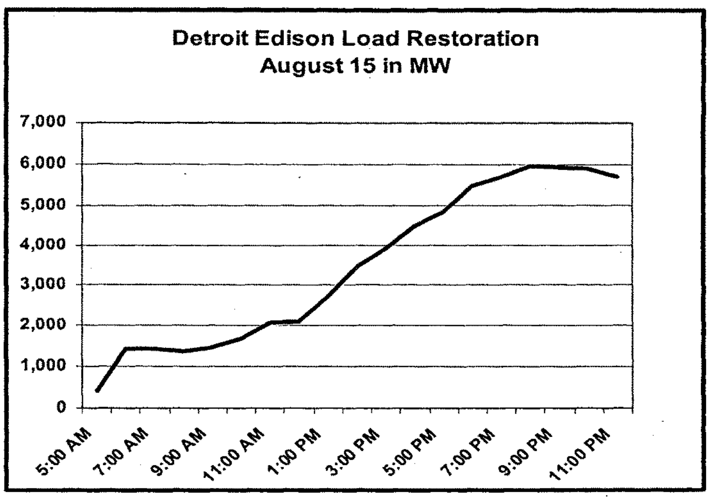
patrol activities. An additional call to discuss these issues was scheduled with Consumers Energy, Detroit Edison, MECS, METC and ITC for 2:30 pm. After this call, power flows on these ties decreased within applicable limits as generation within the Detroit Edison/ITC system increased.

Concerns were monitored and discussed via conference calls throughout the weekend as preparations were made for Monday business.

Section 3.5.2: Detroit Edison

The Detroit Edison service territory-wide outage invoked the utility's black start procedures. These procedures were initially developed after the 1965 outage and direct all of the available field operations staff to the proper locations to support the restoration effort. Given the telecommunication and traffic issues that occurred immediately after the incident, these procedures saved valuable time restoring the system.

Chart 3.7



Detroit Edison was faced with the difficult prospect of restarting its entire collection of generation facilities as listed in Chart 3.6 from a near black start position. This term is referenced in textbooks and technical literature to describe a situation in which a power plant is being brought online with a transmission system that is not energized. While utilities maintain procedures for this condition, it is not frequently encountered. A black start condition is particularly challenging because for most generation, power is required to begin the process.

The turbine must begin to turn to start fluid flow, and steam generation, water flow and compressed air are also required during start up. These functions require electrical power, and that power must be made available either through the transmission system or local stand-by generators.

Chart 3.8

Unit	Initial Inspection Results	Synchronizing Time	Full Load	Comments
Trenton Channel 7A (110MW)	No issues found during initial inspection	August 15, 2003 0916 hrs	August 15, 2003 1430 hrs	
Trenton Channel 8 (100MW)	No issues found during initial inspection	August 15, 2003 0330 hrs First attempt on August 14, 2003 at 2340 hrs	August 15, 2003 1430 hrs	
Trenton Channel 9 (520MW)	No issues found during initial inspection	August 19, 2003 1405 hrs	August 20, 2003 0550 hrs	69 SS Transformer available for unit restart at 0400 hrs on August 15. Turbine vibration was reduced with a balance shot. Load continues to be limited to 475 MWs due to high vibration.
Monroe 1 (770MW)	Unit was in an outage at the time of the event	August 18, 2003 0359 hrs	August 18, 2003 1156 hrs	
Monroe 2 (750MW)	Four failed rupture discs were found/replaced, loss of control air on generator seal oil system valves resulted in oil in the generator	August 19, 2003 0114 hrs	August 19, 2003 1700 hrs	
Monroe 3 (750MW)	Four failed rupture discs were found/replaced	August 17, 2003 0152	August 17, 2003 1330 hrs	
Monroe 4 (775MW)	No issues found during initial inspection	August 16, 2003 0747 hrs	August 16, 2003 1605 hrs	Initially limited due to auxiliary boiler capacity
River Rouge 1 (225MW)	Unit was in an outage at the time of the event	August 15, 2003 1705 hrs	August 15,2003 2100 hrs	
River Rouge 2 (247MW)	Unit was in an outage at the time of the event	August 16, 2003 1422 hrs	August 16, 2003 1830 hrs	HP collector repairs were being conducted at the time of the event
River Rouge 3 (272MW)	The MTG was placed on turning gear to straighten the shaft.			The bearings were found to be damaged during an attempted start. This unit will require several weeks to repair and is not expected to be operational again until late September.

Another factor affecting return to service of generation units is synchronization. When connecting a power plant to the electrical system, the frequency, voltage and phase of the plant's output must be made to match the rest of the electrical system. If this is not the case, the shaft and equipment on the shaft could be severely damaged and require months to repair.

Large generators and their associated equipment require a ramp-up period before they can be placed under full load conditions. The thermodynamic aspects of operating power plants require operators to maintain the plant at a low output level for a period of time to allow the components to reach thermal stability. Once this point is reached, the plant can be pushed to full load.

Chart 3.8 (continued)

Unit	Initial Inspection Results	Synchronizing Time	Full Load	Comments
Belle River 1 (625MW)*	Three failed rupture discs were found/replaced	Attempted synchronization on August 15 at 2100 hrs - Lack of field excitation prevented synchronization		Inspection revealed a failed exciter. Exciter problems were corrected and the unit was returned to service on August 14, 2003 at 1317 hrs
Belle River 2 (635MW)*	Three failed rupture discs were found/replaced	August 16, 2003 1245 hrs	August 17, 2003 0045 hrs	
St. Clair 1 (153MW)	No issues found during inspection following the unit trip	August 15, 2003 1924 hrs	August 17, 2003 1000 hrs	Unit remained on the 120 kv system during the initial event - Tripped off line during switching operations on August 14, at 1832 hrs Following restart load was limited due to a ground in the No Load/Low Load trip switch
St. Clair 2 (162MW)	No issues found during initial inspection	August 15, 2003 1223 hrs	August 15, 2003 2000 hrs	
St. Clair 3 (171MW)	No issues found during inspection following the trip	August 15, 2003 0541 hrs	August 15, 2003 1300 hrs	Unit remained on the 120 kv system during the initial event - Tripped off line during switching operations on August 14, at 1834 hrs
St. Clair 4 (158MW)	No issues found during initial inspection	August 15, 2003 1645 hrs	August 15, 2003 2300 hrs	
St. Clair 6 (321MW)	Initial inspection revealed a boiler water circulating pump overheated	August 16, 2003 0948 hrs	August 16, 2003 1500 hrs	Boiler water circulating pump overheated and had to be replaced prior to start-up
St. Clair 7 (450MW)	Failed rupture discs found/replaced	August 15, 2003 1901 hrs	August 16, 2003 1300 hrs	Difficulty with turbine turning gear, precipitators and ash handling

Failure to follow this procedure can substantially damage key equipment on the generating unit and require months or years to correct.

The Harbor Beach power plant (103 MW) tripped off-line during the event on August 14 but was restored to service within a few hours. Greenwood Energy Center (785 MW) was restored to service mid-day on August 15. Unit 15 (150 MW) and unit 16 (65 MW) at Conners Creek power plant were restored to service by mid-day on August 16. Ludington Pumped Storage Facility remained available throughout the restoration effort. Fermi 2 (1130 MW) tripped off-line during the event and was restored to service on August 20, 2003. The time period to start Fermi was longer due to the procedures required for nuclear power plants. A timeline for the remaining major plants is provided in Chart 3.8[20]. In addition to the work described in Chart 3.8, the Dean Power Facility (an independent power producer) was returned to service at 8:15 p.m. August 14 and Detroit Edison personnel resolved issues at various peaking facilities to provide 950 MW of additional capacity on August 15.

In addition to Detroit Edison's generation, purchases from outside the service territory in coordination with independent power producers were crucial to a timely restoration. This was an effective method of restoration, but expensive. Some purchases were $87/MWh or more. A normal summer on-peak purchase cost would be around $50/MWh. Detroit Edison also coordinated filling the Ludington Pumped Storage Facility with Consumers Energy during the night of August 14 to prepare for load restoration on August 15. To prevent rolling blackouts in Consumers Energy's territory, Detroit Edison allowed Consumers Energy to use some of this stored energy on August 15.

Detroit Edison's System Operations Center (SOC) was monitoring the steady state condition of the transmission system at the time of the blackout. There were no indications or notifications of impending problems prior to the blackout, which occurred in a matter of seconds. After the blackout, the first actions taken were to determine the state of the system. Within a few minutes, the system supervisors determined the following:

- System frequency was zero.
- St. Clair Power Plant had two units running in stable condition and serving an island of approximately 89 MW.
- A group of customers were being served in the thumb through an interconnection.
- A group of customers in the Pinckney area were being served by the Majestic interconnection.
- Harbor Beach Power Plant had tripped, but was operational.
- Several interconnections were still energized and available to support the restoration effort.

In addition to the field operations staff, six additional system supervisors, three engineers and several application engineers joined the available SOC staff within an hour to support the restoration effort. Shortly after the incident, numerous members of senior management arrived in SOC to assess the incident and ensure that the proper resources were available. Within 3 hours, additional support was made available from DTE Energy's generation operations and major account services organizations.

The 1965 plan, which had since been updated on numerous occasions, was used as a guideline by SOC. The SOC team broke up into north and south teams. The intent was to begin restoring the 120kV transmission loops around the service territory and provide a source of electricity for power plants to use to start and synchronize. In the early hours of the blackout, the focus was to restore a source of power to the plants and switch load back onto the electrical system in a safe

[20] Chart 3.8, the Generation Restoration Timeline, was prepared by Detroit Edison shortly after the blackout and provides a contemporaneous accounting of the status of each of the company's generating units immediately prior to, during and subsequent to the blackout. We note that the data for the return to service of Belle River 1 is in error. The unit actually returned to service on August 24 at 1:17 p.m. Otherwise we believe that the information is correct.

and orderly manner. The effort was complicated by numerous external factors. Most significantly, releases of hydrocarbons and evacuation around the Marathon Oil refinery blocked several plans the SOC team formulated to reach some of the southern power plants. The team eventually achieved this goal with police support.

The service territory-wide outages include the following counties: Wayne County, Oakland County, Monroe County, Macomb County, 10% of Lapeer County, 25% of St. Clair County and the eastern half of Livingston County – all which had lost power within a 5 minute period. The following counties were not affected because the Atlanta–Karn–Thetford 120 kV and the Hemphill–Hunters Creek 120 kV interconnections to Consumer Energy remained in service: Sanilac county, the northern 90% of Lapeer County, and the northern 75% of St. Clair County. In the southern portion of the system at Majestic station, the 345 kV interconnections with Consumers Energy and the 345 kV interconnections with FirstEnergy remained in service, which allowed the western half of Livingston County to remain in service following the event.

After the blackout, Detroit Edison found it was in the following condition: (1) the St. Clair Units 1 and 3 were available but isolated in an area near the facility; (2) the Atlanta –Karn–Thetford interconnection to Consumers Energy/METC was energized; (3) all 345 KV interconnections to Majestic Station were closed and energized; (4) the Allen Junction–Majestic–Monroe transmission line was energized into the Monroe Power Plant; and (5) the Majestic lines were feeding and carrying Madrid and Genoa Station load. At this point all plants were ordered to initiate black start procedures.

In its restoration process Detroit Edison focused on first energizing a 120 kV path to connect power plants and re-establishing the available inter-connections to neighboring utilities. The first step taken was to restore power to the Harbor Beach plant and Greenwood Energy Center. In the northern part of the system, the Atlanta–Karn–Thetford 120 kV and the Hemphill–Hunters Creek 120 kV interconnections were utilized to provide restoration paths to Harbor Beach and St. Clair power plants. This allowed Harbor Beach generation to start and load was restored in the remaining portions of Lapeer County by 8:00 p.m. Also, a source of power to start the St. Clair plant and Dean generation was established. The St. Clair 120 kV bus[21] was restored at 8:15 p.m. and the St Clair peakers were started.

During the same period on the south side of its service territory, Detroit Edison was able to isolate a path between the Monroe Power Plant, Brownstown Station, Fermi nuclear plant and the Trenton Channel plant. Between 10:00 p.m. and 10:30 p.m., the Allen Junction–Majestic–Monroe interconnection between Detroit Edison and FirstEnergy was used to establish a restoration path from Monroe to Brownstown to Fermi. An additional path was isolated from Brownstown to Navarre Station to Waterman Station. This provided Detroit Edison with the ability to provide station power to these units in preparation of the process of restoring them to service. Just before midnight the lines to Trenton Channel from Brownstown were energized.

Early in the morning of Friday, August 15, Detroit Edison restored the Pontiac–Hampton interconnection, which further strengthened Detroit Edison's interconnection with the Consumers Energy/METC system and allowed a restoration path to be established to the

[21] "Bus" is short for bus bar, a conducting bar that carries heavy currents to supply several electric circuits.

Greenwood power plant, the Belle River power plant, and St. Clair Units 6 and 7. The Essexville-based generation of Consumers Energy could now assist in the restart. The restoration of interconnections with the Consumers Energy/METC also allowed Detroit Edison to use the Ludington Pumped Storage Facility and purchases from AEP to assist in the restoration process. The Belle River Power Plant–Greenwood–Pontiac Station connection was also restored. This connected the Detroit Edison units at Belle River and the Greenwood Energy center to the system. At this point the Greenwood peakers were started.

Around 3:00 a.m., the 120 kV Trenton Channel–Airport line was re-energized to restore power to Metro Airport, which began restoration of critical facilities.

At 3:18 a.m., Remer Station was restored from the St. Clair generation facility to allow Dean Generation to restart. This connected an additional 300 MW of generation to the Detroit Edison system.

At 3:30 a.m., Detroit Edison energized Brownstown–Navarre–Waterman line. The River Rouge Power Plant could not be reached due to Marathon Oil Refinery incident, which required evacuation of the area surrounding the refinery.

Between 3:55 a.m. and 4:43 a.m., the Belle River–St. Clair 345 kV line was restored, along with the Belle River–Jewel interconnection. This action tied the Belle River and St. Clair power plants into the system, so they could begin supporting the restoration activity. By 5:00 a.m., the restoration of the Pontiac–Hampton 345 kV interconnection, and the interconnection to the Greenwood plant, the Belle River power plant, and St. Clair Units 6 and 7 allowed the restoration of approximately 10% of the load in northern Macomb and Oakland Counties and approximately 20% load in St. Clair County.

Restoration of interconnections from St. Clair plant through Stephens station to Northeast station allowed Northeast peakers to feed into the system. This allowed the load to be picked up in the remaining portions of St. Clair County and approximately 70% of Macomb County. Also by 5:00 a.m., additional paths were established which allowed power to be restored to the northern 1/3 portion of Monroe County and Southern 1/3 portion of Wayne County.

Between 7:00 a.m. and 8:00 a.m., a path from Navarre to Waterman was established to provide a source of power to get the Delray peakers started. This path was then extended to provide the River Rouge power plant with a source of power. As these paths were energized a small amount of load in the City of Detroit was restored. Additional lines and substations were energized by noon to pick up additional load in the City of Detroit. Paths were energized between Majestic station and Pontiac station to connect the southwest and northwest portions of the system. Paths were energized between Waterman and Northeast stations to connect the northern and southern portions through the City of Detroit.

The Blackfoot Station–Madrid Station line was re-energized at 8:55 a.m. and at 9:30 a.m. Detroit Edison closed the ring bus at Pontiac. These actions coupled with the restoration of the Bismark–St. Clair line set the stage for restoration of customers in the Pontiac area.

The restoration of distribution load continued with Grayling Station and Malta Station at 9:35 a.m. Further stations were restored between 9:00 a.m. and noon, when lines were energized into Cato Station, St. Antonie Station and Zug Station picking up more load in the City of Detroit as Detroit Edison continued its practice of closing in whole distribution centers without isolating individual circuits

At 10:51 a.m., Stephens–Victor was closed and tied to the St. Clair facility – this action allowed the restoration of distribution load at Victor. At 11:55 a.m., Detroit Edison personnel energized the Lincoln 120 kV buses and transformers. After the evacuation requirements associated with the Marathon Oil Refinery incident were lifted, operators were able to return to the Navarre station and restore all of Navarre between noon and 1:30 p.m.

Just after noon the Caniff 120 kV buses from Northeast and the Sterling 120 kV buses from Jewell were energized. At 12:42 p.m., Detroit Edison energized the Sterling 40 kV buses, the Pont Wixom–Wixom connection and then Malta–Red Run at Malta. The preparation to restore power to Detroit continued with the energizing of Jewell–Stephens at Jewell at 12:50 p.m. and the energizing of Northeast–Stephens at Northeast at 1:02 p.m.

At 1:24 p.m., Detroit Edison closed the 345 kV ring at the St Clair power facility fully connecting the facility to the 345 kV system.

Between 1:30 p.m. and 2:30 p.m., all of the 120 kV system at the River Rouge power facility was restored. The River Rouge facility was now positioned to fully assist in the restoration of the Detroit area.

The Jewell–Thetford interconnection was tied in at 1:38 p.m., which further strengthened the interconnection with Consumers Energy/METC.

At 1:45 p.m., the preparation to restore substantial portions of the City of Detroit load continued as Stephens was tied to the 120 kV system (this tie would be energized at 2:30 p.m.), Caniff–Stephens was energized at Stephens, and the Mack 24 kV buses were energized. The Erin 120 kV system was energized from Stephens via Erin at 1:53 p.m.

For the most part, these actions were preparatory. The restoration of distribution load began in earnest at 2:30 p.m. when the distribution load at Mack was restored. Further activity at the sub-transmission level continued in order to prepare for additional load restoration in the Detroit area with the energizing of the Northeast 24 kV buses and the Lincoln 24 kV buses and transformers. Activity continued at the transmission level as Bismarck–Stephens and St. Clair–Stephens were energized and Caniff–Stephens at Caniff and Mack–Northeast at Mack were closed.

Bloomfield Point at Pontiac (230 kV) was energized at 2:45 p.m. and the Bloomfield 120 kV buses were energized via Bloomfield–Troy at 3:00 p.m. The 345 kV ring at Bismarck was closed during the same time period. The Jewell buses and Spokane 120 kV buses via Jewell–St. Clair were energized at 3:20 p.m. and Bloomfield–Pontiac at Bloomfield was closed at 3:44 p.m.

At 4:00 p.m. the distribution load was restored at the Jewell sub-station. Shortly after that, Detroit Edison energized the Saturn and Frisbie interconnection, the Sloan bus, and Alpha bus from Sterling.

The Mack–Voyager line at Mack was energized at 4:30 p.m., followed by the Chestnut 120 kV buses from Lincoln. The Chestnut–Red Run line was closed at Red Run at 5:10 p.m. and the distribution load at Red Run was restored.

Detroit Edison energized the Essex 24 kV system at 5:30 p.m., which restored distribution load in the City of Detroit. At 5:40 p.m., Detroit Edison energized the Apache 120 KV and the Seneca 120 KV buses, followed by the closure of Essex–Voyager. At approximately 5:30 p.m., the Detroit Water Works was energized.

Paths were energized from Northeast station towards Bloomfield station at the same time paths were energized from Pontiac station to the Bloomfield station. This allowed load to 50% of Oakland County to be restored at 7:00 p.m. During this period of time, paths were also energized from Northeast station to the City of Detroit.

Restoration efforts required coordination between restart of generating units and transmission operations. ITC was in contact with Detroit Energy's SOC and Emergency Headquarters during the restoration effort, but was dependent on Detroit Edison personnel to complete restoration work because the Detroit Edison transmission system was recently sold to ITC and the sales agreement included a maintenance agreement until January 2004. Consequently, Detroit Edison's SOC restored the transmission system, and the utility's System Planning and Engineering organization arranged for visual and thermal inspections of the transmission system.

Because of concerns for the continued reliable operation of the transmission system, the SOC team requested transmission inspections on August 16 at approximately 2:00 a.m. This initial request was delayed until storm conditions abated. On August 16, ITC requested inspections as well. Detroit Edison used visual and thermal inspections performed from the ground and the air. ITC and Detroit Edison jointly prioritized the inspections.

On August 17, Detroit Edison began visual inspections of all interconnections using helicopter patrols and focused on detecting mechanical defects. The patrols were completed with no major mechanical problems identified. Also on August 17, Detroit Edison personnel began thermovision ground patrols. The focus of this effort was to perform close inspections of critical equipment in the 345 kV and 230 kV switching yards, not easily seen from the air. All 120 kV equipment contained in these yards was also inspected. One helicopter team and two ground teams were assigned on August 17.

On August 18, two thermovision-equipped helicopters began patrols, which allows them to look for overheated connections on the interconnection ties. Fifteen inspections were completed by Tuesday, August 19. On Tuesday, August 19, ITC supplied two additional thermovision-equipped helicopters. All four helicopters patrolled the 345 kV corridors between stations looking for overheated connections. Patrols of most of the 345 kV and 230 kV critical equipment and the thumb area north of I-69 were completed on August 19. On Wednesday, August 20, the remaining 345 kV and 230 kV patrols were completed before moving on to the 120 kV stations, as prioritized by ITC based on the size and the complexity of the station. All helicopter thermovision patrols were completed by 4:00 p.m. Thursday, August 21, 2003. Approximately 1,500 miles of transmission line were inspected in five days.

On Wednesday August 20, the ground patrols for the remaining 120kV stations began and were completed by August 30 as requested by ITC. Over 50 stations were inspected from the ground in 14 days.

After the event on August 14, work crews were held to support the restoration effort, but the major portion of the distribution effort began on August 15 as the generation and transmission systems became functional again. Distribution support was critical to ensure that load was properly restored to maintain system stability. The effort was frustrated by the "In Service Application" not being available due to the blackout.[22] The effort was also constrained by the difficulties of maintaining fuel for corporate and employee vehicles and the sporadic availability of the communication systems. The unavailability of the "In Service Application" required work orders to be faxed to regional operations centers. In some cases, the communication issues required work crews to drive back to the service centers to acquire their next set of work orders. The August 16 storm also complicated the restoration effort. Approximately 500 distribution engineers, lineman and other employees were involved in the distribution restoration efforts.

Early in the outage Detroit Edison established a communication link with the Detroit Water and Sewerage Department (Detroit WSD). Without water, sanitation issues became a major problem. In addition, hospital operating rooms could not function nor could they provide adequate care in emergency situations. Detroit Edison worked closely with the Detroit WSD Director to identify the priority pumping stations and worked to restore the four units that would have the most impact on operations. These were restored throughout Friday with the final critical station restored by early Friday evening.

Section 3.5.3: Lansing Board of Water and Light

At 6:02 p.m., the Lansing BWL began to establish a cranking path to allow the use of Consumers Energy generation to assist in the restoration of station power to its generation facilities. By 6:30 p.m., a cranking path had been established to Eckert Station and the Erickson facility. By 10:07 p.m., the Erickson generation was back on-line and at 10:19 p.m. Lansing BWL restored its first group of customers. Most of the Eckert Station units returned to service just after midnight, with Unit 5 returning at 3:16 a.m. At 4:21 a.m., on August 15, Lansing BWL restored service to the last circuit of customers. The time period from the start of the event to full restoration was just over 12 hours and 10 minutes.

[22] In Service Application is a computerized field force coordination function used by Detroit Edison to prioritize and dispatch its repair crews.

Section 3.6: Review and Analysis

In our opinion, the restoration after the blackout by The Detroit Edison Company, Consumers Energy Company, and the Lansing Board of Water and Light was fully acceptable.

The restoration effort was made possible by the automatic opening of the interconnections between Consumers Energy/METC and Detroit Edison/ITC, which protected the transmission equipment of both systems from damage. During the initial phase of the restoration process, this was the only electrical connection that Detroit Edison had with other power supplies. This transmission link also connected Detroit Edison with its generation facilities at Ludington, another essential tool in the restoration process. In addition, Consumers Energy provided cranking power to assist the Lansing BWL in restoring service.

Michigan systems had options that could have been exercised and that may have prevented the spread of the blackout into Michigan. Detroit Edison, given adequate warning, could have unloaded the METC and ITC interconnections between itself and Consumers Energy in advance of the event. An unloaded interconnection may have weathered the power surge and spared the Detroit Edison system from the blackout.

In the heavily interconnected power system of today, almost every major action taken by an entity connected to the grid is capable of impacting the electric system within Michigan. The events that precipitated the blackout occurred beyond the view of the system operators in Michigan. With no advance warning, the operators were unable to take any action to protect customers from the impending outage. As discussed more completely in Part II, adequate reliability standards and an effective enforcement organization are required to ensure the reliability of Michigan systems.

Additionally, it appears likely that two factors hampered the restoration efforts. First, the computerized "In Service Application" system used to dispatch and coordinate personnel was inoperable. This system was clearly not designed for a blackout of this magnitude, which required the first use in Michigan of widespread black start procedures. The lack of emergency power for this system required additional time and effort for restoration. The "In Service Application" process has performed satisfactorily during other, smaller outages. In our opinion, Detroit Edison should conduct an analysis of the "In Service Application" process to determine what modifications are warranted in light of the experience gained in this restoration effort. Detroit Edison should report to the Public Service Commission on the results of its analysis.

The second factor was the failure of rupture disks at four of the Detroit Edison generating units. The failed rupture disks slowed the pace of restoration. Six of the 13 plants without failed rupture disks were returned to full load on August 15 and three more on August 16. Conversely, none of the plants with failed rupture disks were returned on August 15 and only one on August 16.

However, the presence of failed rupture disks does not, in itself, indicate a problem that needs to be corrected. Rupture disks are a design feature – they are intended to fail under certain conditions, thereby avoiding more serious damage to equipment. Thus, there is a trade-off involving the avoidance of major damage and the potentially more frequent occurrence of outages due to failed rupture disks. An analysis of the operation of rupture disks and the trade-offs involved requires specialized engineering expertise, which the PSC Staff does not possess. Accordingly, we recommend that Detroit Edison analyze the operation of the rupture disks on its units, including a comparison with the operation in other utility systems affected by the blackout, to determine whether any changes are warranted. Detroit Edison should report the result of its analysis to the Commission.

Section 3.7: Recommendations

We make the following recommendations:

1. That Detroit Edison conduct an analysis of the "In Service Application" system to consider modifications or alternatives that would function more effectively in the event of a similar blackout and report the results of its analysis to the Commission.

2. That Detroit Edison conduct an engineering analysis of the operation of the rupture disks to determine if any modifications are warranted and report the results of its analysis to the Commission.

PART IV

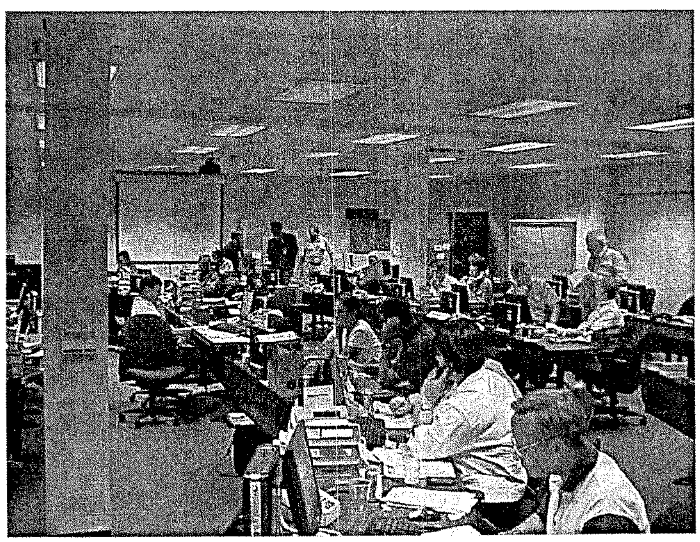
EMERGENCY PLANNING AND RESPONSE

Section 4.1: Introduction

This part of the report addresses specific response measures initiated in Michigan as a result of the blackout of August 14, 2003. It further makes recommendations on specific actions that should be considered as a means to improve the response to a power outage of this type in the future. It should be remembered that there has never before been a blackout of this nature in Michigan. As we look for solutions to prevent a reoccurrence, the focus should be on reducing risks and vulnerability to all hazards. While some problems did develop, to a considerable degree the response went as planned and worked well, and more serious problems were largely averted.

The sections of this report present a description of the roles and responsibilities of the PSC and various other State and federal agencies (Section 4.2); a discussion of the response by PSC, its Staff, and the State of Michigan Emergency Management Team (Section 4.3); and lessons learned and recommendations for improving future State responses (Section 4.4).

Michigan State Emergency Operation Center
August 14, 2003



Press Conference August 15, 2003

Section 4.2: Roles and Responsibilities

To understand the sequence of events and actions taken, it is important to understand the roles and responsibilities of the PSC and its Staff for energy emergency preparedness and response. The PSC is charged with assuring that sufficient energy resources are available to Michigan's citizens and businesses at competitive prices.[23] As part of this charge, the Commission has two separate but related responsibilities. The first is energy emergency preparedness. If a supply problem develops with natural gas or electricity, the Commission has adopted through rules and orders the procedures that a utility will use to respond, which include provisions for reporting on its actions to the Commission. If an energy emergency requires mandatory State action, the Governor, upon recommendation of an interdepartmental Energy Advisory Committee or at her own initiative, may declare a State of Energy Emergency under 1982 PA 191, as amended (MCL 10.81). The Governor may order mandatory actions following such a declaration.

Second, if the situation worsens, or another event such as a tornado, flood, or terrorist attack occurs, the Governor can declare a State of Disaster. In this case, the primary responsibility of response efforts shifts to the Emergency Management Division (EMD) of the Michigan State Police (MSP), through which the PSC Staff would provide a support function. In addition, each department of state government has designated an Emergency Management Coordinator (EMC)

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[23] MCL 460.901

who represents the department and coordinates departmental resources that may be needed to respond to any given event. PSC Staff have been assigned to serve this function in the Department of Consumer & Industry Services (CIS, but soon to become the Department of Licensing and Economic Development), in addition to the Commission's responsibility for energy-related matters.

Section 4.2.1: Energy Emergency Act

The Energy Emergency Act grants the Governor broad powers in the event of a Declaration of an Energy Emergency. These include the following, as described in the Act:

"10.84 Powers of governor during energy emergency.

Sec. 4. During an energy emergency, the governor may do all of the following:

1. Order specific restrictions on the use and sale of energy resources. Restrictions imposed by the governor under this subdivision may include:
   a. Restrictions on the interior temperature of public, commercial, industrial, and school buildings.
   b. Restrictions on the hours and days during which public, commercial, industrial, and school buildings may be open.
   c. Restrictions on the conditions under which energy resources may be sold to consumers.
   d. Restrictions on lighting levels in public, commercial, industrial, and school buildings.
   e. Restrictions on the use of display and decorative lighting.
   f. Restrictions on the use of privately owned vehicles or a reduction in speed limits.
   g. Restrictions on the use of public transportation, including directions to close a public transportation facility.
   h. Restrictions on the use of pupil transportation programs operated by public schools.

2. Direct an energy resource supplier to provide an energy resource to a health facility; school; public utility; public transit authority; fire or police station or vehicle; newspaper or television or radio station for the purpose of relaying emergency instructions or other emergency message; food producer, processor, retailer, or wholesaler; and to any other person or facility which provides essential services for the health, safety, and welfare of the residents of this state.

3. By executive order, suspend a statute or an order or rule of a state agency or a specific provision of a statute, rule, or order, if strict compliance with the statute, rule, or order or a specific provision of the statute, rule, or order will prevent, hinder, or delay necessary action in coping with the energy emergency. The governor may not suspend a criminal process or procedure or a statute or rule governing the operation of the legislature. At the time of the suspension of a statute, rule, or order or a specific provision of a statute, rule, or order, the governor shall state the extent of the energy

shortage and shall specify the provisions of a statute, rule, or order which are suspended, the length of time for which the provisions are suspended, and the degree to which the provisions are suspended. A suspended statute, rule, or order shall be directly related to an energy emergency."

Section 4.2.2: Energy Advisory Committee

Section 10.82 of the Energy Emergency Act provides for an Energy Advisory Committee (EAC), which is responsible for notifying the Governor of an impending energy emergency. When the EAC determines that an energy emergency is imminent based on information from the PSC and other sources, the Governor is informed and may respond by declaring a State of Energy Emergency. The monitoring activity to forewarn of the potential for an energy emergency is provided by the Michigan Energy Appraisal[24], which is issued twice a year in the spring and fall by the PSC. In recent years, the Commission has also directed Consumers Energy, Detroit Edison and American Electric Power to report on how they plan to meet peak summer needs, and PSC Staff has held weekly conference calls with the utilities over the summer months to monitor supply and demand conditions. The Governor may also declare an energy emergency on her own initiative. The EAC is comprised of the Directors of the Departments of CIS, Agriculture, Community Health, Transportation, and MSP. It is chaired by the Chair of the PSC, as provided for in Executive Order 1986-17 (MCL 460.901).

Previous to the August power outage, the EAC had met twice – in the spring of 1979 to respond to shortages arising out of the oil distribution caused by the Iranian Revolution, and in June 2000 in response to the potential gasoline shortage from the Wolverine Pipeline break in Jackson.

Section 4.2.3: Energy Emergency Management Team

In the case of an energy emergency or in anticipation of such an emergency, the Chair of the MPSC may convene an Energy Emergency Management Team (EEMT). The EEMT will monitor developments, prepare assessments, and develop responses. The EEMT consists of senior PSC Staff, including representatives from the Commission Operations and Energy Operations Divisions. The PSC Chair is responsible for convening the EEMT, assigning tasks to its members, and providing information developed by the EEMT to the Governor and EAC. In general, the EEMT responsibilities include monitoring developments, preparing assessments, and implementing responses on a day-to-day basis. Each member of the EEMT will appoint appropriate staff to support EAC work on a priority project assignment basis.

Section 4.2.4: Michigan Emergency Management Plan

Michigan Emergency Management Plan (MEMP) is the State's overall disaster response and recovery plan. There is a basic plan as well as specific plans that address specific types of

[24] http://www.cis.state.mi.us/mpsc/reports/energy/current/

disasters, including: nuclear accidents, enemy attacks, natural disasters, and technological disasters. The August 14 power outage fell under the technological disasters category. In each of these areas, each department's roles, responsibilities and authorities are identified. In addition to this plan, each department and agency has one or more planning documents which supports in further detail the departmental or agency response. This plan is currently undergoing updates and revisions.

It should be noted that, in addition to the PSC responsibilities for coordinating energy emergencies, the manager of the Energy Data & Security Section is also the Emergency Management Coordinator (EMC) for CIS. The EMC plays a critical role in ensuring that the department is capable of implementing the tasks assigned to it in the MEMP before, during, and after a disaster or emergency. To that end, each EMC must be concerned with the following responsibilities within their department:

- Developing procedures for carrying out responsibilities assigned by the MSP;
- Conducting departmental reviews of procedures developed and making revisions where appropriate (subject to the approval of department director);
- Developing necessary support documents (standard operation procedures, resource lists, telephone notification lists, etc.);
- Ensuring staff are aware of and trained for assigned responsibilities;
- Revising procedures as conditions change (i.e., in organizational structure, departmental mission, resource base) in conjunction with EMD/MSP;
- Conducting a training needs assessment on an annual basis to identify personnel who, by virtue of their position or area of responsibility, need to receive emergency management training;
- Getting important emergency management information into the hands of all appropriate department personnel; and
- Developing contacts with federal agencies and private sector organizations within the department's sphere of responsibility that could be called upon to assist in disaster response and recovery operations; and, representing the department in the SEOC to coordinate department response and recovery activities, and to establish communications with department field personnel.

There are two PSC divisions with primary responsibilities in energy emergency planning and response activities – the Commission Operations Division (COD) and the Energy Operations Division (EOD). The energy emergency responsibilities of these divisions fall into four broad categories:

- Monitor Michigan's energy supply system for the purpose of detecting unusual imbalances that may indicate the potential for an energy emergency and advising the appropriate state officials in such events;
- Develop, administer, and/or coordinate energy emergency contingency plans;
- Act as the communication focal point for federal, state, and local activities related to energy emergency planning and management; and
- Maintain ongoing contact with the petroleum, natural gas, and electric industries concerning Michigan's energy situation.

During the power outage, a number of PSC Staff provided support at the SEOC. In particular, the manager of the Energy Data & Security Section in COD and the safety manager in EOD spent considerable time in the SEOC working with the MSP and other state officials monitoring the situation and providing consultation for the Governor and the EAC on what Michigan's rules and regulations regarding energy emergencies entailed.

Section 4.3: Response by the PSC and the State's Emergency Management Team

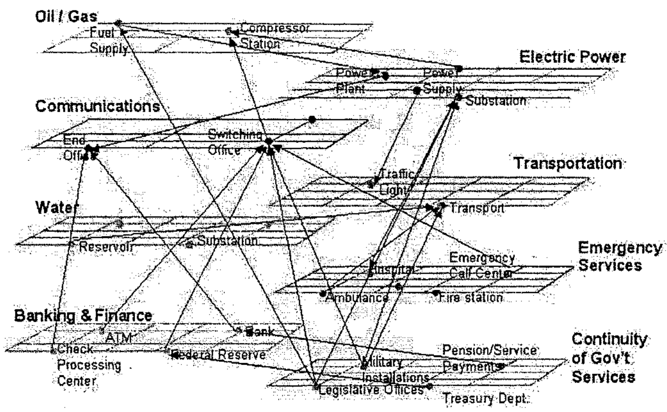
This section addresses PSC, Staff, and State government involvement in responding to the outage and its secondary effects. At the onset of the power outage, PSC Staff went immediately to the SEOC to manage power outage responsibilities from that site. The SEOC has a backup generator and lighting, computer access, and phones were available throughout the emergency. Other PSC Staff remained at the PSC offices at Mercantile Way in Lansing for a number of hours until it became impractical to continue due to sunset. These Staff members used cell phones for communication.

The PSC provided staffing at the SEOC from 4:30 p.m. on Thursday, August 14, 2003, until 2:30 a.m. on Friday, August 15, returned by 6:45 a.m. that Friday and remained until midnight. Staffing on Saturday, August 16, was provided from 7:00 a.m. to 5:30 p.m. During this time, there were always at least two PSC Staff members at the SEOC and sometimes three. In addition, PSC Chair Lark was on-site for a briefing on each of these days. Although power had been restored to all customers by Saturday morning, the concern remained that continued voluntary conservation measures were required to reduce demand, while a number of Detroit Edison power plants returned to operation. If electric demand exceeded Detroit Edison's available generation, it could have been necessary to implement rotating power blackouts. Therefore, PSC Staff's focus on Saturday, August 16, was to monitor Detroit Edison's ability to balance load.

During and following the power outage a number of issues arose that required response. These issues clearly demonstrated the critical interdependencies that exist that support our citizens and businesses. The National Strategy for the Physical Protection of Critical Infrastructures and Key Assets[25], issued in February 2003, describes the interdependencies as follows: "The facilities, systems and functions that comprise our critical infrastructures are highly sophisticated and complex. They consist of human capital and physical and cyber systems that work together in processes that are highly interdependent. They each encompass a series of key nodes that are, in turn, essential to the operation of critical infrastructures in which they function. To complicate matters further, our most critical infrastructures typically interconnect and, therefore, depend on the continued availability and operation of other dynamic systems."

[25] National Strategy for the Physical Protection of Critical Infrastructures and Key Assets, February 2003. See: http://www.whitehouse.gov/pcipb/physical_strategy.pdf

Interdependencies[26]

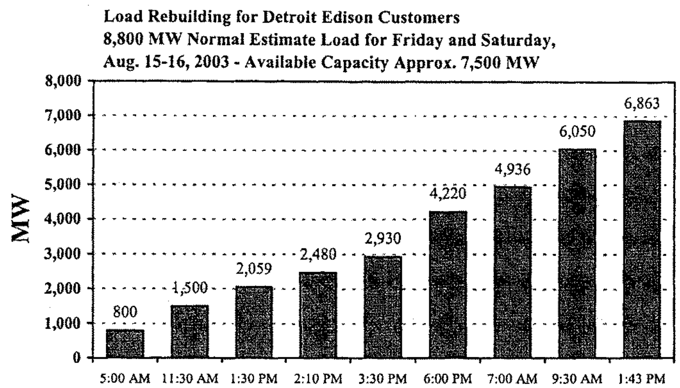


Following are some of the key issues and actions taken at the SEOC to respond to the outage in which many of the critical interdependencies were clearly demonstrated.

Section 4.3.1: Power Outage Status Assessment, Analysis and Reporting

This was one of the primary functions of the PSC Staff, with the assistance of Detroit Edison personnel who arrived at the SEOC on Friday morning. The SEOC held periodic briefings with each of the departmental agencies, providing a summary of events, issues, and problems in their area of responsibility. The computer systems normally used by Detroit Edison were not available to the company due to the power outage and, therefore, the number of customers that were without power could not be provided. Typically, this information is available in situations such as storm outages and provides the basis for assessing the severity of the problem and rate of restoration. Absent this information, the recovery of the system and restoration of power was monitored in three ways. First, Detroit Edison personnel in the control center provided information on the load being served. This was a measure (albeit indirect) of the rate at which customers were being restored, and the trend by early Friday afternoon was encouraging. The following graph was prepared and circulated at the SEOC as an indicator of the restoration rate.

[26] Figure provided by the U.S. Department of Energy, Office of Energy Assurance.



Second, reports from city and county emergency operation centers provided further information as areas were restored. Third, one of the early indications of the extent of the outage was a map that showed the state's 800 MHz radio system towers that were operating on emergency backup generators.

Section 4.3.2: Collecting Information

As soon as the PSC Staff arrived at the SEOC, they began a systematic inquiry directed to the operations centers and emergency personnel at the affected utilities to ascertain the extent of the power outage and the status of a return to power. The U.S. Department of Homeland Security informed us that the blackout was not an act of terrorism. We also communicated with DOE and regional energy officials. After ruling out a terrorist act, the question quickly turned to the source and extent of the blackout. First reports on the early evening of Thursday, August 14, suggested a power plant was on fire in New York City, and then it was a transformer. Next, reports came in that lightning had hit a power plant operated by the Niagara Mohawk utility in western New York, problems in Canada were then suggested, and at one point ABC News reported that the problem originated in Michigan. None of these reports proved to be accurate, but each was checked to determine if the information could be verified. Later reports began to focus on transmission lines in northern Ohio that tripped off the system. Web site searches on news sites was one means used to track the reports that were coming in, sometimes second and third hand, and suffering the distortion that occurs as information is removed further and further from its source.

NERC, located in Princeton, New Jersey, was an important source of information. A conference call held by NERC on Friday, August 15, provided a helpful update and a preliminary report of events posted to the NERC web site was provided to the Governor on Saturday morning, August 16.

Section 4.3.3: Public Information Needs

One of the most important crisis management actions state government takes during an emergency is to provide information to the public. Timely, accurate information about an emergency can help prevent confusion and uncertainty, as well as enlist the support and cooperation of the public. It is also important that the public understand what caused the emergency and what needs to be done to ease and eventually resolve it. The Michigan Energy Emergency Operations Manual provides a useful guide on how a public information program should be used and operated in an energy emergency. Following these guidelines, the PSC provided information to the Governor and the public regarding the status of the power outage, what steps were being taken to resolve the situation, and how the public could help.

The PSC public information efforts started at the onset of the power outage. Early in the evening of August 14, two PSC Consumer Alerts were faxed to the Governor's office from the SEOC. The alerts were entitled "Tips For Buying And Using A Portable Generator" and "Surviving Electrical Power Outages – What You Can Do If You Lose Your Electric Service." This information was then modified to reflect the current outage conditions and posted to the Michigan.gov web site (see Appendices A-8 and A-9).

Also on the first night of the power outage, we provided information to the Governor and her staff on the affected utilities' power restoration efforts in preparation for her WKAR television broadcast appearance at 10:00 p.m. the night of August 14.

In the days following the power outage, PSC Staff continued to provide information as needed on utility restoration efforts, reports on preliminary causes of the power outage, and other outage-related information to the Governor and the public. The Governor and the PSC Chair utilized this information during the press conference that was held at noon on August 15. Also on August 15, the PSC issued a press release asking Michigan citizens throughout the State to conserve electricity to reduce demand and help stabilize the system in light of the fact that a number of power plants were off line, both in and out of the affected area.

At the request of the Governor's press office, during and following the outage, the PSC responded to media inquiries from the trade press; national press (New York Times, Boston Globe, Washington Post, Reuters, Associated Press, Dow Jones, Wall Street Journal); and Michigan media (WJR, WWJ, WDET, Michigan Public Radio, Detroit News, Detroit Free Press, Oakland Press, Jackson Citizen Patriot, Booth newspapers; and Bay City Times). A number of these entities wanted specifics on the geographic areas affected by the power outage. In these cases, we directed them to the PSC web site where maps of the affected service territory areas could be found.[27]

[27] http://www.cis.state.mi.us/mpsc/electric/map.htm

After the power had been restored, the PSC continued providing information on the power outage. On September 3, 2003, the PSC Chair testified before the U. S. House Committee on Energy and Commerce on the power outage.

Section 4.3.4: Declaration of Emergency

On the morning of Augsut 15, Governor Granholm declared a State of Emergency under the provisions of both the State's Disaster Act and the Energy Emergency Act.

With this declaration, two things needed for coping with the power outage and a possible gasoline shortage occurred: 1) the declaration allowed petroleum suppliers to import gasoline to make up for the dislocation of supply, and 2) a driver hour waiver provision automatically went into effect under contingencies established by the Federal Motor Carrier Safety Administration (FMCSA) that would allow the drivers of trucks carrying gasoline and other needed supplies into the Detroit area to drive for extended hours.

The initial declaration was followed up on August 22 by a Declaration of Energy Emergency caused by the fact that the power outage had adversely affected eight refineries in the U.S. and Canada, including the Marathon refinery in Detroit. The loss of production at the damaged refineries posed the potential for a gasoline shortage for the Detroit Metro area, creating the potential for an energy emergency. A second Executive Order, also issued on August 22, 2003, continued the suspension of rules for gasoline vapor pressure because strict compliance with the rule could "...prevent, hinder, or delay necessary action..." to cope with a gasoline shortage.

The basic authority for the Governor's ability to issue the Executive Orders discussed above comes from two pieces of legislation. First, the State's emergency management legislation (1976 PA 390) was enacted in December 1976 and amended in April 1990. This act replaced Michigan's Civil Defense Act and broadened the scope of emergency management. Act 390 also brought the State into compliance with provisions of the Robert T. Stafford Disaster Relief and Emergency Assistance Act (P.L. 93-288, as amended), which provides federal assistance in declared (by the President) emergencies or major disaster situations.

The Governor also acted under Section 10.82 of the Michigan Compiled Laws (MCL), 1982 PA 191, as amended. The purpose of this act is to allow for the declaration of a state of energy emergency, to provide for procedures to be followed after a declaration of a state of energy emergency, to create an energy advisory committee (EAC) to the governor and prescribe its powers and duties, to prescribe the powers and duties of the governor, to prescribe penalties, and to repeal certain acts and parts of acts. The EAC is chaired by the Chair of the MPSC, as provided for in Executive Order 1986-17. Under the provisions of Act 191, the Governor can declare an energy emergency on her own initiative or at the advice of the EAC. During the power outage and subsequent events involving the damaged refineries, the EAC Chair provided information to the Governor advising that an energy emergency was potentially imminent. The Governor subsequently declared an energy emergency.

Section 4.3.5: Contacts

There were considerable contacts between the State and other agencies, both local and federal, DOE and the Department of Homeland Security (DHS), and other states. Staff members at the SEOC were in communication with both federal agencies and other states. Generally, communication worked, although there is always room for improvement. The evolving relationships and emergent roles of DOE and DHS are in need of clarification. The information from federal agencies in Washington was somewhat fragmented, and available information was not always made readily available. The DOE has been working with state officials to prepare a protocol that would enhance information exchanges and coordination between states and the federal government in an energy disruption, such as the power outage. This will require a better delineation of energy emergency responsibilities between DOE and DHS. Several DOE functions, including an office that had oversight of critical energy infrastructure, were transferred to DHS.

The DOE Office of Energy Assurance (OEA) is working on a procedure for communication that can be used in any kind of energy disruption. This should allow for a more systematic sharing of information between the states and federal government to assure that information is rapidly distributed to key participants and to avoid misinterpretation of information. OEA played a major role in DOE's response to the blackout, assisting state and local authorities and industry, and advising Energy Secretary Abraham.

Section 4.3.6: Telephone System Operation

In the early evening hours of August 14, it became apparent that there was an issue concerning fuel required for standby generators used by the local phone system. In addition, a number of government offices and private entities were operating generators in order to maintain power at their own sites and were competing for limited fuel supply. Although all had arrangements with fuel suppliers, some suppliers and distributors did not have the capability to pump the fuel from underground storage tanks without power or their own generators.

Another problem that came up Friday night involved a critical site, which handles all 911 calls in Oakland County, which was running on standby generators. Because the generators were not fully capable of meeting cooling needs due to the hot weather at this site, additional generators were moved to this location when power was restored Friday evening. The generator at this site was relocated to other critical needs. There is now a plan to add additional generation at this location.

The local phone system, which is operated by SBC, requested assistance from the SEOC in locating supplemental supplies of gasoline, kerosene, or #1 diesel fuel to assure the continued operation of the local telephone system. This fuel was needed for both standby generators and company vehicles to allow travel to remote locations to assure continued operation of equipment. During the power outage, more than 3 million customer lines in the central offices and 380,000 customer lines serviced by remote terminals could have been impacted by the loss of commercial power. However, because of SBC's emergency backup procedures, only 50,000 customers were impacted for a little over an hour. And this was despite the fact that the blackout generated an increase of 149 percent in the volume of calls placed on the SBC network.

Initially, 120 central offices and 2,300 remote terminals lost commercial power throughout Lansing and southeast Michigan. However, by using backup generators and batteries, SBC was able to maintain service in the offices and to the remote terminals even though they were without power for an average of 28 hours. Only the Mt. Clemens north central office was impacted, and those customers could not call outside of their local area for 68 minutes during the early morning on Friday, August 15.

As indicated, SBC called the SEOC for assistance and the PSC Staff at the SEOC identified a number of suppliers that had fuel available and could supply SBC's needs. Ultimately, SBC spent almost $650,000 purchasing 320,000 gallons of fuel. Some of that fuel was purchased from suppliers identified by the SEOC and some of it from existing suppliers.

SBC owns two large trailer-mounted generators and a number of smaller portable generators; in addition, SBC borrowed two larger generators from a local manufacturer and moved these generators around to meet their needs. Each of the 2,300 remote terminals needed to have their batteries periodically recharged. SBC accomplished this by having its technicians move portable generators to a terminal, powering up the generator until the terminal batteries were fully charged, and then moving the generator to another terminal and repeating the process. This was an additional challenge because a number of terminals are in rural locations and not easily identifiable, particularly at night.

No long distance companies reported any problems, in part, because their services are dependent on the operation of the local phone system. In addition, because many had developed business continuity plans; they were able to continue operations. Some cell phone companies did lose service for a time, and as the duration of the outage became more extended, they were also at the point of needing additional supplies of fuel for generators; however, the power was restored before this became a problem.

Section 4.3.7: Communications[28]

There was full and robust communication between the appropriate federal and State agencies, although further improvements can be made. DHS and the Federal Emergency Management Agency (FEMA) in DHS were in regular, consistent contact with the SEOC. DEQ, MPSC, and the National Guard were communicating with the EPA, DOE, and the National Guard Bureau, respectively.

Two suggestions for improvement can be made, however. First, the reports given to both DHS and FEMA Region V were redundant. While the pace of the emergency response was such that this was not a serous problem, this redundancy should be eliminated as the reorganization of federal agencies within DHS is completed. Some material was sent over phone lines by

[28] Some of this information is taken from the Congressional Testimony of Col. McDaniel, Homeland Security Advisor to the Governor, to House Select Committee on Homeland Security, September 17, 2003.

facsimile, but e-mail with text-based documents would have been a better alternative, since the information can more readily be shared and incorporated within E-Team. Second, all communication was by telephone and, given the intermittent outages of commercial telephone service elsewhere in the State, a backup system needs to be instituted that is not reliant on commercial lines. There is a wireless system between FEMA Region V and the SEOC, and this capability could be expanded.

The DOE Office of Energy Assurance (OEA) is working to enhance and expand the Energy Emergency Information Coordinators (EEIC) Program[29] with the assistance of the National Association of State Energy Officials and the National Association of Regulatory Utility Commissioners. This program provides a point of contact in each state for information on energy supply, availability, and potential distribution problems. This set of contacts will be expanded to include contacts in public utility commissions on matters related to electric and gas supplies. While the vehicle for communication is principally based on non-secure e-mail at present, other communication technologies will be examined as part of this effort. It is intended to provide for an additional communication channel between the states and federal government to provide for the exchange of information between and among states. These contacts provided for some of the communication that occurred during the power outage. To be successful, this system will need broad-based participation by the states, and information to be shared must be reliable, timely and useful.

Internal communications, both within a State agency and between employees of the State and local agencies, worked very well. Over the last 12 years, the State of Michigan has spent in excess of $220 million to create a statewide 800 MHz digital trunk radio system. This system provides full interoperability for all organizations using it. Currently, 374 different public agencies use the Michigan Public Safety Communications System as their primary radio communication, and another 90 agencies use the system for emergency management purposes only. The member agencies include all state agencies, as well as counties, townships, tribes, and federal agencies (the FBI, U.S. Customs, Bureau of ATF, and Forest Service). There are currently more than 11,000 radios on the system.

There were no interruptions to the system anywhere during the blackout because the control center and all antennae have independent generators. Four of the five affected counties, as well as many municipalities within those counties in the declared emergency area, are now considering joining the Michigan Public Safety Communications System.

Section 4.3.8: Cyber Systems

Cyber systems were shut down in areas affected by the power outage unless they had backup batteries or generation. Many computers and nearly all servers supporting large-scale systems operate with Uninterrupted Power Supply (UPS) units. The UPS provides power conditioning (controls fluctuations in current and voltage which can damage circuitry), and when power is lost automatically shifts over to battery backup and then directs the server to a controlled shutdown

[29] http://www.naseo.org/eeic/default.htm

to avoid errors in software operations. When power is resumed, the servers then reboot, as normal, bringing operation systems back on line. In not all instances will this execute properly and some servers will require a technician to bring the system back on line. In some cases the age of equipment may have been a factor in returning the system to operations.

Computer operations, which run multiple servers, also require cooling in the server room. Since the outage occurred on a hot summer day, it was necessary to get air conditioning systems back into operation, allowing the server room to be cooled to normal operating temperatures before the servers could be returned to service if back up generation was not available.

A significant challenge faced by computer system operators was that the outage occurred in the middle of an effort against the "MSBLASTER" worm virus attack and the "SoBig" virus. The system attacks as a result of these two viruses had already caused some disruptions to computer systems and the power outage compounded the problems and the response.

Many of the State of Michigan's computer operations were affected. Most Lansing and southeast Michigan computer hardware encountered a hard shutdown, with the exception of most voice systems. The Department of Information Technology (DIT) Command Center was without power in the Hannah Building in downtown Lansing.

Actions taken by DIT included a quick response to assure most servers in data centers were powered down prior to exhaustion of UPS battery power to eliminate problems when power was restored. The DIT Emergency Management Coordinator went to SEOC at 7:15 p.m. on Thursday, August 14, and a DIT secondary command center was activated at the State Secondary Complex, which still had power. Additional fuel to power these generators was not available when planned due to the heavy demand on fuel suppliers, and these server operations were cut over to power from the grid at about the time fuel supplies for the generator were exhausted.

Additionally, the following actions were taken:

- Established an ongoing DIT conference call for problem resolution and status updates.
- Identified all critical customers facing processes, i.e., Food Stamps, UA checks, CSES batch, Medicaid provider batch run, etc.
- Performed modification so Governor could update Michigan.gov Web site.
- Identified status of existing second and third shift staff and established a plan of action for scheduling critical work.
- Worked with Department of Management and Budget (DMB) to restore failed air conditioning units.
- When power returned, waited until data centers had cooled and followed start up procedures in all buildings.
- Resolved network and hardware issues caused by failed components on Friday, August 15, in Lansing area and through Monday in Detroit.

One of the lessons learned in the computer system operations was that any disaster recovery planning that had been done previously proved very helpful in the recovery of systems. For many, the procedures that came out of the preparation for the rollover to the year 2000 (Y2K) helped immensely and exercises held since then were also very useful. The use of toll free conference calls proved to be an invaluable communication tool, as cell phones could not always be relied on. It was also clear that contact lists need to delve deeper into the organization and need to be listed on paper.

Section 4.3.9: Water and Wastewater Systems[30]

Detroit operates the largest water and wastewater utility in Michigan and the third largest in the U.S. It serves 4.3 million people in 126 communities in nine counties in southeast Michigan. Highly trained and certified professionals operate well-maintained water and wastewater treatment facilities. The drinking water facilities consist of five water treatment plants, 22 booster-pumping stations, and over 13,000 miles of water transmission and distribution mains. The system also consists of telemetry and automated SCADA equipment. The drinking water produced at the water treatment plants and pumped throughout the distribution system is monitored in accordance with Michigan DEQ requirements for chemical, microbiological and radiological contaminants.

Detroit lost power to all pumping stations at the five water treatment plants, as well as system control telemetry. Of these five plants, Springwells, Southwest and Lake Huron used backup generators to restart within hours. Several communities called the system's control center to complain of low or no pressure; however, many communities were able to maintain reduced pressure due to location and storage capacity. One Detroit Edison power feed was restored to the Lake Huron water treatment plant at approximately 7:30 p.m. on August 14. The three plants combined supplied approximately 430 million gallons per day (mgd) of drinking water to the distribution system during the blackout. Six (of 22) booster-pumping stations have backup generators, but only four stations were functional during the blackout. The annual average water demand for the Detroit Water and Sewerage Department (Detroit WSD) system is approximately 600 mgd. With prompt implementation of water restrictions during the blackout, 430 mgd of water should have been sufficient to maintain pressure in the distribution system.

A "boil water" advisory was issued for the entire Detroit WSD service area at 7:15 p.m. on August 14 and rescinded at 3 p.m. on August 18. The boil water advisory was necessary because of a system-wide pressure loss that resulted from the blackout. The large number of residents and communities affected by the water emergency, the high level of involvement by state and local officials, and the potential health implications made this a serious matter of concern.

Rule R 325.11206 of the Michigan Safe Drinking Water Act (PA 399 of 1976 and Administrative Rules) reads, "For a type I public water supply, a means shall be provided to continuously supply finished water to the entire distribution system during periods when the normal power service is interrupted." This rule was implemented by requiring each water treatment plant to have a minimum of two electrical feeds from two separate substations, backup

[30] Much of the information in this section is taken from *A Report on the Detroit Water and Sewerage Department System during the Blackout of 2003, August 2003,* prepared by the Michigan Department of Environmental Quality, Water Division, Field Operations Section, Southeast Michigan District Office.

generators, or sufficient gravity storage. The Detroit system exceeded this requirement at all water treatment plants and six booster stations. Each of the Detroit water treatment plants and booster-pumping stations has two electrical feeds from two separate substations, with the exception of Waterworks Park and Northeast, which has three separate feeds from three separate substations. Springwells, Lake Huron, and Southwest water treatment plants have backup generators able to deliver approximately 430 mgd total (near average day) to the distribution system. Six booster-pumping stations have backup generators as well.

The separate electrical feeds provide for a contingency more frequently seen with storm outages where some localized areas are affected and others are not. This outage was highly unusual in that the entire electrical system failed and the power companies were required to initiate black start procedures. Under these procedures the process begins at the power plant and restores the power moving from the plant outwards. Restoration of service to water treatment plants is an important priority in the overall electrical power restoration effort.

During the August 14 power outage, wastewater utility professionals attempted to minimize negative impact from the sanitary sewer system. All wastewater systems are unique, and it is up to the licensed wastewater professionals to handle emergencies to affect the least damage and best outcome based on the capabilities of their systems.

In addition to some wastewater systems having emergency backup electrical generators, some wastewater systems without backup power were able to store sanitary sewage in the gravity collection system. However, after filling the space in the limited storage of the sanitary sewers, utility personnel were faced with options of either allowing raw sewage to back up into residential basements, with significant public health issues, or overflowing at some point in the system to the receiving waters – a lake or a river. Overflows are typically managed to allow for partial treatment followed by disinfection as much as practicable.

Section 4.3.10: Driver Hour Waivers

The limits on the number of hours truck drivers can normally be on the road were suspended to assist with the recovery and re-supply following the power outage. The Federal Motor Carrier Safety Regulations (FMCSR) (390.23) provide relief from compliance with most safety regulations when an emergency is declared. This means a carrier would have to comply with Controlled Drug and Alcohol Testing (382) and with CDL Requirements (383), but not the provisions dealing with the Driver Qualifications (391), Hours of Service (395) and Maintenance of Vehicles (396). For example, a carrier would be granted relief from complying while providing assistance to the emergency. According to 49 CFR 390.5, an "Emergency means any…storm (e.g., thunderstorm, snowstorm, ice storm…) earthquake…explosion, power outage, or other occurrence, natural or man made, that interrupts the delivery of essential services…or supplies (such as food and fuel) or otherwise immediately threatens human life or public welfare…." Under such situations, the FMCSA Field Administrator may declare emergencies if there is a regional crisis, which justifies such regulatory relief or when an emergency has been declared by the President of the United States, the governor of a state, or their authorized representatives having authority to declare emergencies.

Under a declaration of emergency under CFR Part 390, governors have broad authority to respond to disastrous situations. This authority in nearly all cases would automatically give effect to driver hour waivers upon an emergency declaration by a governor. FMCSA recognized a governor's authority as the basis for granting interstate waivers for drivers supplying the affected areas in a state in relation to disaster situations. Therefore, once Governor Granholm issued the emergency declaration at 9:15 a.m. on August 15, 2003, the waivers automatically went into effect. This waiver helped assure the delivery of needed supplies to southeast Michigan, including water and later gasoline, and remained in effect until the emergency declaration was rescinded. Notification was sent out over the State Police Law Enforcement Network and e-mails were sent to the energy and transportation trade associations informing them of this action. While these waivers should not be employed any longer than needed by companies, they technically remain in effect during the period under which the emergency declaration is in effect. The energy emergency declaration following the power outage was rescinded on September 30, 2003.

Section 4.3.10: Detroit Marathon Refinery[31]

Late on August 14, 2003, reports to the SEOC incorrectly indicated that there was a fire at the Marathon refinery located in southeast Detroit and storage tanks were a concern. What in fact occurred was that when the power went out, the refinery went into emergency shutdown procedures. These procedures provided in part for petroleum products being processed under pressure to be dumped to safety flares. The flares, a safety valve for the refinery, burned off petroleum products in process, producing a flame that was reported to be anywhere from 30 to 75 feet high. Over a darkened city, this was very prominent. In addition, one of the units, a carbon monoxide boiler, did not shut down properly, causing an explosion, resulting in the release of a mixture of hydrocarbons and steam. The reduction in water pressure also was a compounding problem in the shut down of the refinery.

The release of the hydrocarbons and steam created concerns as to whether or not these emissions were toxic. Testing done at the refinery suggested that it was not an immediate hazard and the presence of benzene or hydrogen sulfide was ruled out. However, as a precautionary measure, the immediate surrounding residential communities located in southeast Detroit and Melvindale were evacuated. Additionally, I-75, which runs immediately adjacent to the refinery, was temporarily shut down to facilitate with the evacuation. The hydrocarbon release was contained at the Marathon refinery by about 8:00 a.m. the morning of August 15, and I-75 was opened back up to traffic. However, people that had been evacuated to shelters were not allowed to return to their homes until later in the day on August 15, following additional testing by the EPA, which had come into the area to monitor the air quality effects. Once it was determined that those effects were not harmful, residents were allowed to return to their homes.

The Marathon refinery can process 74,000 barrels of crude oil per day into a variety of petroleum products. Approximately half of the production from the refinery is gasoline. The gasoline being produced at the Marathon refinery at the time of the power outage was of a specification

[31] Celeste Bennett, Michigan Department of Agriculture, provided some of the information in this section.

designed to meet air quality requirements in southeast Michigan. The Motor Fuels Quality Act, P.A. 44 of 1984, as amended, requires that Wayne, Oakland, Macomb, Washtenaw, Livingston, Monroe, and St. Clair Counties use lower evaporating gasoline (7.8 pounds per square inch (psi) Reid Vapor Pressure[32] (RVP) or less) from June 1 to September 15 of each year.[33] This particular specification is intended to reduce evaporative emissions of volatile organic compounds (VOC) from gasoline during the summer months. This program is part of the State Implementation Plan (SIP) submitted to the EPA in 1996 in response to the clean air act mandates. The balance of the state uses RVP 9 psi gasoline throughout the summer and the same RVP limits are in effect statewide for the remainder of the year. The State's failure to enforce the 7.8 psi gasoline requirements could result in federal sanctions of highway dollars or implementation of federal enforcement measures.

Due to the damage at the refinery, it did not go back into full production until August 23, eight days after the onset of the outage. This meant that during that time, the refinery did <u>not</u> produce approximately 500,000 barrels of petroleum products, of which about half was gasoline with the 7.8 psi specification required for southeast Michigan

Marathon alone supplies an estimated 38 percent of the 7.8 psi gasoline used in that area by utilizing full refinery capacity all summer long and bringing in additional 7.8 psi product to meet demand. And, although the Toledo and Sarnia, Ontario refineries were only offline for a day or two, the lost production from these production facilities also contributed to a shortfall in supply of the 7.8 psi gasoline. According to the Energy Information Administration, the Marathon refinery and the two refineries in Toledo typically supply about 6-7 percent of distillate fuel oil (heating oil and diesel) and about 7-8 percent of gasoline demand in the Midwest and are even more important to the upper regions of the Midwest, where they are the major suppliers to Michigan and parts of Ohio. Each day these refineries are down, they do not produce 8 million gallons of gasoline, which is about two-thirds of what the entire State of Michigan uses in one day.

Section 4.3.11: Gasoline Distribution Problems

As a result of the disruption to refinery production both in Detroit and Toledo Ohio, the available supplies of 7.8 psi gasoline were quickly depleted. Only about 9 percent of the stations in the Detroit area were operational during the power outage and they reported customers were lined up in the street filling every canister they could. Stations were not able to replenish their supply of 7.8 psi gasoline because all but one Detroit terminal with 7.8 psi gasoline were without power. The one terminal with power was supplying petroleum products, but would not send their own tanker trucks out because of unsafe road conditions due to the lack of operating traffic signals. Some stations with available gasoline shut down because they were unable to handle consumers' behavior and had concerns for employee safety. Police were dispatched for crowd and traffic

[32] "Reid vapor pressure" means the absolute vapor pressure of volatile crude oil and volatile non-viscous petroleum liquids, except liquefied petroleum gases, as determined by A.S.T.M. D-323-72.

[33] After September 15, gasoline RVP requirements for the Detroit area are as follows: September 16 to October 31 – 13.5 psi; November 1 to March 31 – 15 psi; April 1 to April 31 – 13.5 psi. Ethanol blended fuels are 1 psi higher.

control at numerous stations in and out of the Detroit area as lines of cars backed up for as much as two hours.

Consumers began to migrate west and north in search of available gasoline and operational stations in Pickney, Manchester, and Chelsea reported a run on gasoline. Stations in outlying areas began reporting that they were out or running out of gasoline from the deluge of customers "stocking up." Reports were received of consumers filling as many as 10 portable gas cans at a single purchase. There were reports that at some gas stations tanker trucks could not maneuver through the heavy traffic to get in to restock the stations, even with 9.0 psi gasoline, so some stations were forced to shut down until consumer demand coming out of Detroit had slowed down.

Recognizing the potential supply shortfall of 7.8 psi gasoline in southeastern Michigan, the Governor declared a State of Emergency and a State of Energy Emergency on Friday morning, August 15. At approximately 9:15 a.m., Executive Order No. 2003-10 was issued by the Governor to suspend the environmental specifications for gasoline used in southeast Michigan counties to ensure that the area stations could receive any available gasoline. The DEQ requested that the EPA exercise enforcement discretion in regards to the SIP 7.8 psi requirements in southeast Michigan. The request was granted and was in effect until midnight on Friday, August 22. Notification of the suspension of the 7.8 psi requirements was sent out to all Michigan gasoline trade associations. Notice was also sent to Oil Price Information Service, which is utilized heavily by the petroleum industry for up-to-date news.

The following Wednesday, August 24, EAC Chair Lark advised the Governor of an impending energy emergency due to dwindling gasoline supplies as a result of the continued shut down of the Marathon refinery in Detroit. At the request of the DEQ, the EPA extended the state's enforcement discretion for southeast Michigan until September 3. On Thursday, August 21, Executive Order No. 2003-11 was issued by the Governor, which rescinded the State of Emergency and which also declared that an energy emergency existed for the state of Michigan due to the loss of gasoline supplies. That same day, Executive Order No. 2003-12 was issued by the Governor, which continued the suspension of environmental specifications for gasoline required for use in southeastern Michigan.

Inspectors from the Michigan Department of Agriculture, Motor Fuel Quality and Weights and Measures Division, who enforce the specification requirements for the State Implementation Plan under the air quality requirements, determined that a number of stations in southeastern Michigan had taken advantage of the waiver of the requirements and had blended a 9 psi gasoline into 7.8 psi gasoline already in tanks in retail gas locations in the Detroit and southeast metropolitan area. Based upon this information, it became apparent that it would be impractical to drain the tanks of this blended gasoline so that 7.8 psi could be put in place. A complete change over of gasoline stocks from 9.0 psi to 7.8 psi normally requires about a one-month lead time. Once the 9.0 psi product was in the distribution chain, it would continue to impact upon gasoline supplies for several weeks.

By Saturday, August 16, power was restored to much of southeastern Michigan and consumers' gasoline buying habits returned to normal by that evening. Power was restored to the Marathon and Toledo refinery operations, but production could not be resumed until after a total systems check and damage assessments were completed. Sunoco's Toledo refinery was back on line August 17, but Marathon was unable to return to full production until August 23. Other major marketers to southeastern Michigan indicated they had sufficient 7.8 psi gasoline to meet their normal market share, but did not have surplus product to make up for the refinery's shortfalls.

To resolve the shortfall of the availability of the 7.8 psi gas, the DEQ had originally requested that EPA permit the State enforcement discretion until September 5 to allow sufficient gasoline supplies for the holiday weekend. The EPA granted the state enforcement discretion until September 3, at which time a re-evaluation would be done. However, on August 28, because of the commingling tank contamination and the continued potential for problems with obtaining sufficient quantities of 7.8 psi gas, the DEQ requested that the EPA extend the environmental waivers until September 15, at which point the summer specifications would no longer be in effect. The EPA granted this discretion for distribution, transportation and sales until September 15, provided regulated parties took all reasonable steps to produce and supply 7.8 psi gasoline to southeast Michigan.

During this same time, beginning on August 15, a surge in demand for gasoline took place as people in the areas affected by the power outage drove to locations outside the affected area to fill up their vehicles. This resulted in a substantial drain of gasoline supplies around the periphery of the power outage area. In the week that followed the power outage, gasoline prices in both Michigan and the Nation rose at record rates. The average price in the Detroit area prior to the outage was $1.59 per gallon[34] on August 11, 2003. By August 25, the price had increased to an average of $1.77, and just prior to the Labor Day weekend peaked at nearly $1.88 per gallon at many stations. These price increases were not unique to Michigan and, in fact, these increases were seen nationwide.

The reason for the increase in prices seemed to be the result of a combination of events, which included rising crude oil prices through the month of August and a significant increase in gasoline demand that was evidenced by sharp draw downs in gasoline inventories. Even though the loss of refinery production was relatively minor, it nevertheless contributed to a tightening of supply, which further accelerated the price increases. As a comparison, problems with a gasoline pipeline near Phoenix, AZ had caused gasoline prices to go to $4.00 a gallon at some locations for a temporary period of time. Another one of the reasons for the accelerated demand for gasoline was the cooler than normal weather during the months of June and July, which tended to defer travel until August, at which point improved weather patterns caused people to take to the roads in notable numbers. Gasoline prices typically show an increase leading up to the Labor Day weekend and a seasonal decline following Labor Day weekend. This trend has taken place as gasoline prices have now settled back down along with the decline in crude oil prices.

[34] http://www.autoclubgroup.com/michigan/autos/fuel_gauge.asp

Section 4.3.12: Food Supply[35]

The most significant events impacting the food supply were the loss of electricity to power refrigeration and the boiled water advisory that resulted from the loss of municipal water pressure due to the loss of electricity to pumping stations. Large grocery retail chains have contingency plans in place to provide auxiliary refrigeration to impacted stores. Smaller grocery retail establishments and restaurants faced significant challenges to prevent their perishables from becoming compromised.

The Michigan Department of Agriculture's response included directing extensive food safety inspection resources into the area to inspect grocery retail establishments, guidance to local health departments regarding restaurants, and extensive public outreach.

The food and agriculture infrastructure experienced the same difficulties in communications as other sectors. The dependence on cellular and cordless telephones, as well as the computer assisted switching in both the private sector and government made communications difficult.

The lack of the availability of commercial sources of gasoline posed an impediment to responders being sent into the impacted area. Allowing Michigan Department of Agriculture inspectors to fuel at State Police Posts solved this problem.

Resources that would be available in many situations to transport potable water, bulk milk haulers, were busy transporting milk from areas impacted by the loss of electrical power.

The amount of food being discarded by grocery stores posed a public health hazard as an enticement to poor people and an attraction to rodents. Initially, licensed waste haulers were not willing to deviate from their pre-existing contract obligations and landfills were not readily available on the weekend. The loss of electricity created a situation where public health was potentially impacted by the availability of a landfill on a Sunday.

Section 4.3.13: Transportation[36]

The transportation system was also affected by the power outage in the following ways:

- Traffic signals were not functioning which meant, in some cases at busier intersections, police personnel had to be deployed in directing traffic when their services could perhaps have been needed elsewhere.
- Pumps used to keep depressed highways from flooding had to be powered with portable generators. This required crews to work 24 hours a day until power was restored. Some areas received so much rain that the crews could not keep up and some highways (I-94 in St. Clair Shores, M-39 in Detroit) were temporarily flooded.

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[35] Prepared by Robert Tarrent, Emergency Management Coordinator, Michigan Department of Agriculture.
[36] Information in this section was provided by Eileen Phifer, Michigan Department of Transportation, and, in part, was taken from Congressional Testimony of Col. McDaniel, Homeland Security Advisor to the Governor.

- Systems at the Michigan Intelligent Transportation System Center were without power. Video cameras, changeable message boards, and the Center's Web site all went offline. Communications with freeway courtesy patrols, outside media, and Michigan Department of Transportation was nearly impossible until the power was restored.
- The Detroit Windsor Tunnel was shut down due to the inability to operate ventilation, but the Ambassador Bridge continued to operate.
- The Ambassador Bridge in Detroit, the busiest commercial land port in the U.S., with 16,000 tractor-trailers crossing daily, was also affected. Interestingly, both the bridge and U.S. Customs had their computers interrupted only momentarily until their backup systems activated. Canadian Customs, however, lost their computer data link, and thus their ability to verify trucking manifests electronically. As a result they were forced to visually and manually inspect the manifests and, if warranted, the freight itself. This resulted in an approximately four-mile back up of traffic for almost 24 hours on the U.S. side.
- Metropolitan Detroit Airport was closed and all flights canceled until midnight on August 14. Flooding of the approach roads to the McNamara Terminal caused by a storm on August 15 cut off vehicle access to the terminal temporarily.

Section 4.4: Lessons Learned and Recommendations

Even though the State as a whole was well prepared for the events following the August blackout, events such as this serve as a reminder that we can be better prepared. Most of the following items are in areas where work has been done that greatly contributed to the ability to respond to problems caused by the outage, but some gaps in planning and preparedness were evident and should be addressed. In general, improvement efforts need to focus on planning, assessment, communication, and training.

1. Examine the current Emergency Electrical Procedures adopted in Commission Case No. U-4128 to determine if they remain valid. These procedures were last updated in 1979 and the electric utility industry has changed dramatically since then.

2. Update Emergency Gas Procedures manual. Natural gas curtailment procedures have been adopted by the PSC for each jurisdictional gas utility in the State. However, many of these procedures may no longer be effective because large volume customers no longer buy directly from the local distribution utility.

3. Update the PSC Energy Emergency Operations manual. This manual was last revised in May 1992.

4. Update the Department's Emergency Management Coordinator responsibilities as contained in the State Emergency Management Plan currently undergoing revision.

5. Update contact lists and emergency procedures. While the contact lists in existence at the time of the power outage proved invaluable, some deficiencies in the lists were revealed. It is important for PSC Staff to maintain a professional working relationship with the key emergency contacts. Both the emergency contact lists and the communications procedures

have been updated since August 14, 2003. However, in the future, contact lists of emergency numbers – work, home and cell/pager – and e-mail addresses need to be kept up to date. This should be done on a regular schedule, preferably annually, and should include the following groups:

A. State agencies
B. Industry/private sector and non-profits
C. Federal agencies

6. Provide for additional PSC Staff training. PSC Staff that worked at the SEOC during the outage included individuals that were selected due to their availability, not necessarily their expertise in energy emergency procedures. A total of six individuals provided support at the SEOC. Additionally, a number of PSC individuals from public information, Energy Operations Division, and Energy Data & Security Section provided support to those at the SEOC from the Commission offices on Friday, August 15, 2003. While Staff at both the SEOC and the Commission offices provided invaluable help and support, previous training in the workings of the SEOC and energy emergency procedures would have been helpful. It is suggested that PSC Staff should be pre-designated to serve this function in case of future energy emergencies. Staff should be trained in the procedures of both the SECO and energy emergency procedures and should participate in annual emergency preparedness exercises conducted at the SEOC and elsewhere. The SEOC training should include training in the use of E-Team,[37] crises management software, and maintaining a duty log.

7. Training for the Department's Emergency Management Coordinator and alternates should also be provided on the use of E-Team and SEOC procedures. The list of emergency contacts in each bureau should be kept up to date and these bureau contact individuals should meet annually to review and discuss the Department's emergency response procedures.

8. Events should be more fully documented. Staff assigned to the SEOC should be trained in the use of E-Team, and events should be documented as they occur in E-Team. This will mean becoming more proficient in the use of the E-Team software and having better rules as to how this system should be used. Additionally, it is important that both a duty log and a phone contact log be maintained at the SEOC and by PSC backup support from the Commission offices. The PSC Staff assigned to do this support should be familiar with these procedures and trained to keep these records. This information is valuable both for keeping track of the event at the time and for assessing the emergency after it has been resolved.

9. Evaluate interdependencies. Staff working on energy emergencies should be versed in the potential interdependencies involved in such an emergency. For instance, in this power outage, it quickly became apparent that the loss of electrical power seriously affected the water systems of many of the affected communities. This loss had the

[37] E-Team is an incident management software package recently implemented at the SEOC. It includes a data base that provides for tracking of events, allocation of resources, and information sharing.

potential to cause very serious problems had the power outage lasted longer than it did. These problems could have included lack of clean drinking water for public consumption, lack of adequate wastewater treatment abilities, and lack of water for firefighting purposes.

Another interdependency that manifested itself as the power outage progressed was the need for fuel for the generators many entities were running to maintain services (hospitals, telecommunication systems, etc.). While some institutions and businesses had the foresight to have generators in place, they had neglected to contract for fuel deliveries to continue running the generators for an extended period. In some instances, generators fueled by natural gas should be considered.

Staff needs to be familiar with at least the concept of interdependencies and some of the more likely problems to spring from a power outage and related systems. Staff should be versed in potential solutions to some of these problems. For instance, in the case of generators running short of fuel, Staff made calls to area terminals and fuel supply depots in an effort to locate a supply. And, while the solution to interdependency may not lie with MPSC Staff (e.g., with the power outage, traffic signals were not working and police had to be dispatched to busier intersections to direct traffic), they should at least be aware of potential problems so as to advise the appropriate agency.

10. The roles and responsibilities of state and federal agencies and associations need to be clearly delineated, including the U.S. Department of Energy Office of Energy Assurance, U.S. Department of Homeland Security, the PSC, National Association of Utility Regulatory Commissioners, and National Association of State Energy Officials.

11. Good up-to-date reference information should be provided. There is a need to have reference materials available on systems and infrastructure that may be involved or affected by an energy emergency. While PSC Staff had a great deal of this information available when it was needed (Emergency Operations Manual, State rules and regulations governing energy emergencies, contact lists, and statistics readily available regarding the Marathon refinery), some of this information was not readily available because it was contained in an electronic database on computers at the PSC offices. Since the PSC offices were without power, this information was not available. It is important that detailed information on all critical energy infrastructure and any other reference material deemed to be useful be developed and maintained in both electronic and hard copy formats, which will ensure that it is available when needed.

Section 4.5: Conclusion

In conclusion, the efforts of the PSC, its Staff, and other State and federal agency personnel made a significant contribution to avoiding much more serious consequences that might have occurred absent emergency management intervention. Statewide coordination of what turned out to be a widespread regional problem was essential to the maintenance of order and the restoration of public services. Finally, the tireless endeavors of utility personnel and management as well as local first responders were critical in restoring essential services and maintaining public safety throughout the duration of the blackout of 2003. Nonetheless, this report reveals that a number of lessons were learned from this review, and a number of steps should be taken to improve the response to future emergencies.

PART V

CONCLUSIONS AND RECOMMENDATIONS

This part summarizes the most important conclusions and recommendations of this report. It is intended only as a convenient summary of items discussed more fully in the text. The most significant conclusions and recommendations in each sector are included:

Section 5.1: Transmission

- Michigan utilities and transmission companies were not the cause of the blackout. All of the events in the two and one-half hours preceding the power surges that occurred at 4:09 p.m. involved the facilities of FirstEnergy or American Electric Power in Ohio. No Michigan utilities or transmission companies were involved in these events. Information involving these events was not shared with Michigan companies prior to the blackout.

- Congress must provide the FERC with the authority and responsibility to ensure (1) that mandatory reliability standards are in place, (2) that they are enforceable, and (3) that they include penalties for noncompliance.

- FERC should permit but one regional transmission organization to operate in the Midwest market; but if it chooses to permit the existence of more than one organization, at an absolute minimum, there must be mandatory, enforceable rules that address issues that arise at the seams between the organizations.

Section 5.2: Electric Utilities

- Detroit Edison should conduct an analysis of the "In Service Application" system to consider modifications or alternatives that would function more effectively in the event of a similar blackout, and should report the results of its analysis to the Commission.

- Detroit Edison should conduct an engineering analysis of the operation of its rupture disks to determine if any modifications are warranted and report the results of its analysis to the Commission.

Section 5.3: Emergency Response

- There should be a review of the Emergency Electrical Procedures adopted in Case No. U-4128, which have not been updated since 1979.
- The Public Service Commission should designate in advance the Staff assigned to the State Emergency Operations Center and provide training for that assignment.

Appendix A

1. Governor's Statement to the People of Michigan
2. Executive Proclamation State of Emergency
3. Executive Order No. 2003-10
4. Executive Order No. 2003-11
5. Executive Order No. 2003-12
6. Executive Order No. 2003-16
7. Tips For Buying And Using A Portable Generator
8. Surviving Electrical Power Outages
9. MPSC Press Release, August 15, 2003

Appendix A-1

Governor's Statement to the People of Michigan

Aug. 15, 2003

The following is the text of Governor Jennifer M. Granholm's statement to Michigan residents regarding the power outage, which was broadcast via satellite on Thursday evening:

Let me begin by reiterating what you all heard the President of the United States say just an hour ago. The electrical outage that we are experiencing here in Michigan is not the result of a terrorist attack, but appears to be the result of some other natural occurrence – that caused an outage at a power plant in New York State earlier this afternoon. That outage in New York rippled across the Eastern United States and Canada, actually stopping here in Michigan.

At this hour, utility crews are working to restore power in the affected areas. As you know by now, the outage affects mostly residents in the middle and southeast parts of the state. Detroit Edison serves 2.1 million customers in these areas, all of which are still out of power as I speak. In addition, 100,000 Consumers Energy customers are without power.

Detroit Edison is saying that they are beginning to power-up their plants and they will continually be bringing customers back online. The utility cannot confirm exactly when all power will be fully restored, but they are hopeful that most customers will be back online before the end of the weekend. This will be a gradual restoration, but I am pleased to report that thanks to the swift response of utility crews and the power conservation of our citizens, reports are beginning to trickle-in that power is slowly coming back on in some locations.

Oakland, Macomb and Wayne Counties have declared LOCAL states of emergency. At 8:30 p.m. we fully activated the state's Emergency Management Operations Center, which allows us to have a central point of communication between the all state, local and federal agencies.

Some people may have questions about steps they can take to remain safe and protect their families. We urge citizens, first and foremost, to remain calm. Also, for your safety, try to stay off the roads. If you must drive, treat all intersections as four-way stops.

Beyond these important first steps, we encourage citizens to take the same basic precautions that you would in any other power outage situation.

Unplug your appliances and major electronics – like computers, for instance. When power comes back on there may a surge which could damage these products.

Importantly, while we encourage people to stay hydrated to stay cool, citizens should take steps to conserve water. Water is pumped to your faucet through pumps, which, of course, use electricity.

As the evening and tomorrow progresses, we expect more communities to come back on-line. I want to thank all of the utility workers and emergency personnel who have been working so hard to restore power.

Finally, this is truly one of the instances where we are all in this together. So please be calm, be supportive of your neighbor, and take those extra precautions. Thank you.

Appendix A-2

STATE OF MICHIGAN
OFFICE OF THE GOVERNOR
LANSING

JENNIFER M. GRANHOLM
GOVERNOR

JOHN D. CHERRY, JR.
LT. GOVERNOR

EXECUTIVE PROCLAMATION

STATE OF EMERGENCY

WHEREAS, beginning on August 14, 2003, significant portions of the State of Michigan are experiencing the effects of a severe power outage, resulting in the loss of electrical power for countless Michigan residents, communities, and businesses, causing serious hardship for the citizens of the State of Michigan;

WHEREAS, this power outage has resulted in the loss of power in numerous other states in the region, including Connecticut, Michigan, New Jersey, Ohio, Vermont, and the province of Ontario;

WHEREAS, the power disruption has impaired and or threatens to impair the maintenance of essential public services, and therefore constitutes a danger to the health, safety, and welfare of the general public;

WHEREAS, this event was caused by a utility failure and represents a threat of widespread or severe damage, injury, or loss of life or property;

WHEREAS, it is in the best interests of the State of Michigan and its citizens that appropriate measures be taken to assure that essential needs are met, and where necessary, discretionary needs are met;

WHEREAS, the areas affected include the counties of Macomb, Monroe, Oakland, Washtenaw, and Wayne;

NOW, THEREFORE, I, JENNIFER M. GRANHOLM, Governor of the State of Michigan, pursuant to powers vested in me by the Michigan Constitution of 1963 and the provisions of the Emergency Management Act, 1976 PA 390, MCL 30.401 to 30.421, and 1982 PA 191, MCL 10.81 to 10.87, proclaim:

1. A state of emergency, including an energy emergency, exists in the counties of Macomb, Monroe, Oakland, Washtenaw, and Wayne.

2. The response and recovery aspects of the Michigan Emergency Management Plan and the emergency operation plans of affected political subdivisions are activated to manage the state of emergency.

3. The Emergency Management Division of the Michigan Department of State Police ("EMD") shall coordinate and maximize all state resources which may be activated to assist the affected areas in responding to the impact of the power outage and facilitate the restoration of power in the affected areas. The EMD may call upon all state departments to utilize resources at their disposal to assist in the emergency area pursuant to the Michigan Emergency Management Plan.

4. Termination of this state of emergency will occur at such time as emergency conditions no longer exist and appropriate programs have been implemented to recover from the effects of this emergency, but in no event longer than September 14,2003, unless extended as provided by the Emergency Management Act, 1976 PA 390, MCL 30.401 to 30.421.

This proclamation is effective immediately.

Given under my hand and the Great Seal of the State of Michigan this 15th day of August, 2003.

JENNIFER M. GRANHOLM
GOVERNOR

BY THE GOVERNOR:

Secretary of State

FILED WITH SECRETARY OF STATE
ON 8-15-03 AT 9:15 AM

Appendix A-3

STATE OF MICHIGAN
OFFICE OF THE GOVERNOR
LANSING

JENNIFER M. GRANHOLM
GOVERNOR

JOHN D. CHERRY, JR.
LT. GOVERNOR

EXECUTIVE ORDER

2003 — 10

TEMPORARY SUSPENSION OF ADMINISTRATIVE RULES FOR GASOLINE VAPOR PRESSURE

WHEREAS, because significant portions of the State of Michigan have been experiencing the effects of a severe power outage, resulting in the loss of electrical power for countless Michigan residents, communities, and businesses, and causing serious hardship for the citizens of the State of Michigan, a state of emergency was declared by proclamation on August 15,2003 in the counties of Macomb, Monroe, Oakland, Washtenaw, and Wayne ("State of Emergency");

WHEREAS, Section 5(l)(a) of the Emergency Management Act, 1976 PA 390, MCL 30.405, empowers the Governor to suspend a regulatory statue, order, or rule prescribing the procedures for the conduct of state business when strict compliance with the statute, order, or rule would prevent, hinder, or delay necessary action in coping with the disaster or emergency:

NOW, THEREFORE, I, JENNIFER M. GRANHOLM, Governor of the State of Michigan, pursuant to powers vested in me by the Michigan Constitution of 1963 and the provisions of the Emergency Management Act, 1976 PA 390, MCL 30.401 to 30.421, order:

1. Administrative rules promulgated by the Department of Agriculture, Laboratory Division, dealing with gasoline vapor pressure, entitled, "Regulation No. 561-Dispensing Facility Reid Vapor Pressure," 1997 AACS, R 285.561.1 to 285.561.10, are suspended in the areas of the State of Michigan subject to the State of Emergency and the counties of St. Clair and Livingston for the duration of the State of Emergency.

This Order is effective immediately.

Given under my hand and the Great Seal of the State of Michigan this 15th day of August, 2003.

JENNIFER M. GRANHOLM
GOVERNOR

BY THE GOVERNOR:

Secretary of State

FILED WITH SECRETARY OF STATE
ON 8-15-03 AT 12:55 P.M.

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www.michigan.gov

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Appendix A-4

JENNIFER M. GRANHOLM
GOVERNOR

STATE OF MICHIGAN
OFFICE OF THE GOVERNOR
LANSING

JOHN D. CHERRY, JR.
LT. GOVERNOR

EXECUTIVE ORDER
2003 – 11

STATE **OF ENERGY EMERGENCY**

WHEREAS, Article V, Section 1 of the Michigan Constitution of 1963 vests the executive power of the State of Michigan in the Governor;

WHEREAS, Section 3 of 1982 PA 191, MCL 10.83, authorizes the Governor to declare a State of Energy Emergency upon notification of an impending energy emergency by the Energy Advisory Committee, or upon the Governor's own initiative if the Governor finds that an energy emergency exists or is imminent;

WHEREAS, on August 14,2003, a widespread and unprecedented loss of electrical power affected significant portions of the State of Michigan;

WHEREAS, the power outage adversely impacted operations at eight petroleum refineries throughout the United States and Canada, and damaged Michigan's only refinery, which may be unable to meet demand for gasoline in the near future, resulting, without further action, in a lack of adequate available gasoline in parts of this state;

WHEREAS, on August 20, 2003, the Public Service Commission notified the Energy Advisory Committee of an impending and imminent energy emergency involving a dwindling supply of gasoline in Southeast Michigan due to the power outage and damage to the refinery;

WHEREAS, it is in the best interests of the State of Michigan that appropriate measures be taken in response t o an imminent energy emergency to ensure that gasoline supplies will remain sufficient and t o assure the health, safety, and welfare of Michigan residents and visitors;

NOW, THEREFORE, I, JENNIFER M. GRANHOLM, Governor of the State of Michigan, pursuant to powers vested in the Governor by the Michigan Constitution of 1963 and 1982 PA 191, MCL 10.81 to 10.87, order the following:

1. The State of Emergency proclaimed on August 15, 2003 for the counties of Macomb, Monroe, Oakland, Washtenaw, and Wayne is rescinded.

2. A State of Energy Emergency is declared. Pursuant to Section 3 of 1982 PA 191, MCL 10.83, the State of Energy Emergency is effective until the earlier of either of the following:

a. A finding by the Governor that the energy emergency no longer exists
b. November 19,2003.

This Order is effective upon filing.

Given under my hand and the Great Seal of the State of Michigan this 21st day of August, 2003.

Jennifer M. Granholm
GOVERNOR

BY THE GOVERNOR:

SECRETARY OF STATE

FILED WITH SECRETARY OF STATE
ON 8-21-03 AT 4:00P.m.

Appendix A-5

STATE OF MICHIGAN
OFFICE OF THE GOVERNOR
LANSING

JENNIFER M. GRANHOLM
GOVERNOR

JOHN D. CHERRY, JR.
LT. GOVERNOR

EXECUTIVE ORDER

2003 — 12

TEMPORARY SUSPENSION OF RULES FOR GASOLINE VAPOR PRESSURE

WHEREAS, under 1982 PA 1981, MCL 10.83, during an energy emergency the Governor may by executive order suspend a rule of a state agency if strict compliance with the rule will prevent, hinder, or delay necessary action in coping with the emergency;

WHEREAS, Executive Order 2003-11 declared a State of Energy Emergency beginning on August 21,2003;

WHEREAS, appropriate measures must be taken in response to the energy emergency to ensure that gasoline supplies will remain sufficient and to assure the health, safety, and welfare of Michigan residents and visitors;

NOW, THEREFORE, I, JENNIFER M. GRANHOLM, Governor of the State of Michigan, pursuant to powers vested in the Governor by the Michigan Constitution of 1963 and Michigan law, order that the Regulation No. 561, entitled, "Dispensing Facility Reid Vapor Pressure," promulgated by the Laboratory Division of the Department of Agriculture, 1997 AACS, R 285.561.1 to 285.561.10, be suspended for the duration of the energy emergency declared in Executive Order 2003-11. Additionally, Executive Order 2003-10 is rescinded.

Given under my hand and the Great Seal of the State of Michigan this 21st day of August, 2003.

Jennifer M. Granholm
GOVERNOR

BY THE GOVERNOR:

SECRETARY OF STATE

FILED WITH SECRETARY OF STATE
ON 8-21-03 AT 4:02 P.M.

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Appendix A-6

STATE OF MICHIGAN
OFFICE OF THE GOVERNOR
LANSING

JENNIFER M. GRANHOLM
GOVERNOR

JOHN D. CHERRY, JR.
LT. GOVERNOR

EXECUTIVE ORDER
2003 – 16

END OF STATE OF ENERGY EMERGENCY

WHEREAS, Article V, Section 1 of the Michigan Constitution of 1963 vests the executive power of the State of Michigan in the Governor;

WHEREAS, under Section 3 of 1982 PA 191, MCL 10.83, a state of an energy emergency declared by the Governor is effective for the shorter of 90 days or until a finding that the energy emergency no longer exists;

WHEREAS, the Chairperson of the Energy Advisory Committee has advised that the energy emergency recognized by Executive Order 2003-11 no longer exists;

NOW, THEREFORE, I, JENNIFER M. GRANHOLM, Governor of the State of Michigan, pursuant to powers vested in the Governor by the Michigan Constitution of 1963 and Michigan law, order the following:

1. The state of energy emergency proclaimed on August 21, 2003 under Executive Order 2003-11 is rescinded, effective immediately.
2. Executive Order 2003-12 is rescinded, effective immediately.

Given under my hand and the Great Seal of the State of Michigan this 30th day of September, 2003.

Jennifer M. Granholm
GOVERNOR

BY THE GOVERNOR:

SECRETARY OF STATE

FILED WITH SECRETARY OF STATE
ON 9.30.03 AT 10:58 A.M.

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Appendix A-7

CONSUMER ALERT

Subject: Portable Generators

Contact: Margaret VanHaften
(517) 241.6165
(mrvanha@michigan.gov)
800.292.9555

TIPS FOR BUYING AND USING A PORTABLE GENERATOR

In the event of an electrical power outage, many Michigan homeowners and businesses rely on portable power generators to keep lights and appliances running until service is restored. A portable generator is designed to run a limited number of appliances at a time and is typically powered by gasoline or diesel fuel. Generators usually cost between $600 and $3,000 -- depending on size and features. The Michigan Public Service Commission (MPSC) wants you to consider some important points when deciding to buy and use a portable generator.

Sizing

To determine the size of the generator you will need, total the wattage of the lights and appliances you will need to power. *For example*:

Appliance	Wattage Needed to Run Appliance*
Furnace (1/3 HP blower)	1,200**
Refrigerator	600**
Microwave oven	700
Two 100-watt light fixtures	200
Total	2,700
*Appliance wattage varies -- these figures represent averages. **Allow up to three times the normal running watts for starting these appliances or cycling their compressors.	

A typical portable generator is rated at 2,400 to 7,500 watts. Most household appliances are rated at 120 volts. Some larger electric appliances (e.g., electric range, electric clothes dryer, well pump, air conditioner) are rated at 240 volts. If you want to power this type of appliance as well as smaller ones, you will need a generator that is rated at 120-240 volts.

Installation

Always read and follow all installation and operation instructions for your generator. There are two ways to safely install and operate a portable generator:

Direct Hook-up

Portable generators are designed to power a limited number of plug-in appliances like your refrigerator, freezer, and lights or any other combination of appliances you determine to be essential. These and other home appliances not permanently wired to the electrical system can be powered directly from the generator through a heavy-duty (at least 12 gauge), polarized extension cord. The extension cord should be less than 100 feet long to prevent power loss and overheating.

Safety Transfer Switch

Some generators can be permanently connected to your electric system to energize your home's wiring in the event of a power outage. This type of installation requires a safety transfer switch. Before starting your generator, you must activate the switch. The switch disconnects your home's wiring system from the electric company's system and allows electricity to flow from the generator to your home's circuitry. The switch prevents the generator from back-feeding electricity into the power lines and possibly causing injury or death to unsuspecting workers trying to restore power. The switch also prevents damage to your generator, wiring, and appliances when electric service is restored. Only a licensed electrician should install a transfer switch.

Safety

- Always follow the safety instructions in the manufacturer's instruction manual.
- Always follow local, state, and national fire and electric codes. A permit may be required for installation.
- Always use a heavy-duty (at least 12 gauge) UL-listed extension cord (less than 100 feet long) from the generator to your appliances -- being careful not to overload the cord.
- Always make sure that the total electric load on your generator does not exceed the manufacturer's rating.
- Always properly ground the generator according to the manufacturer's instructions.
- Never operate a generator indoors or in an unventilated area. It produces deadly carbon monoxide fumes.
- Always store gasoline and diesel fuel in approved containers and keep it out of the reach of children.
- Never refuel a generator while it is running. Shut it off and let it cool for 10 minutes before refueling to minimize the danger of fire.
- Parts of the generator are very hot during operation. Avoid contact and keep children away.
- Protect the generator from rain and other moisture sources to prevent electrocution.
- When not in use, store the generator in a dry location such as a garage or shed.

A portable generator can be a good, temporary source of electricity during a power outage. To avoid serious safety hazards when using a generator, it is important to follow all operation and safety instructions provided by the manufacturer.
The Michigan Public Service Commission is an agency within the Department of Consumer and Industry Services.
Alert 99-12
September 30, 1999

Appendix A-8

SURVIVING ELECTRICAL POWER OUTAGES - WHAT YOU CAN DO IF YOU LOSE YOUR ELECTRIC SERVICE

Set aside and designate for emergency use:

- Flashlight
- Battery-powered radio
- Extra batteries
- Blankets
- First-aid kit
- Bottled water
- Battery-operated lantern
- Candles

Keep a list of emergency numbers near the telephone.
Protect electrical equipment such as a TV, VCR, microwave, or home computer with a voltage surge suppressor. A suppressor can eliminate the surge before it enters the equipment, thus protecting it from damage. A variety of devices are available for different forms of protection. If the equipment is not protected, unplug them before the storm begins to prevent lightning damage.

- Check the fuse box to see if a fuse is blown or tripped. Check with the neighbors to see if their power is out.
- Call your local utility company and let its personnel know that you have lost power. Also, advise if there is emergency medical equipment in the home.
- Turn off and unplug most lights and appliances to prevent electrical overload when power is restored.
- Keep refrigerator door closed as much as possible. Move milk, cheese, meats, etc. into the freezer compartment of the refrigerator. If the freezer is only partially full, group packages together so they form an "igloo" to keep each other cold. Cover freezer with a blanket. Purchase dry ice and place in freezer. It will help keep food frozen for an extended period of time.
- Make sure you have enough water for cooking and drinking.
- Avoid downed power lines.

- If city water, open faucets so there is a constant drip so pipes won't freeze.
- Hang cardboard or blankets over windows and doorways - find a well insulated room for living until power is restored.
- Dress warmly - wear a hat because it helps prevent loss of body heat, since body heat escapes through the top of the head.
- Fireplaces may be used to provide light as well as heat. Always keep the damper open for proper ventilation.
- Store perishable food outside in a cold and shaded area or in an unheated garage.

Wait a few minutes before turning on lights. Plug in appliances one at a time.

Appendix A-9

J. Peter Lark, Chair
Robert B. Nelson, Commissioner
Laura Chappelle, Commissioner

Contact: Gary Kitts 517.241.6193 or 517.241-3323 www.michigan.gov/mpsc

Michigan Public Service Commission Urges Energy Conservation in Light of the Recent Blackouts

August 15, 2003

The Michigan Public Service Commission urges Michigan citizens to take all reasonable steps to conserve energy today in light of the devastating blackout through the Northeast.

"Although power restoration is underway, the ability to complete and maintain that restoration will depend on the amount of demand on the system," said Commission Chair J. Peter Lark. "We are asking all Michigan citizens to assist in this effort by conserving energy today to minimize the stress on the electric system. Almost 2 million Michigan customers remain without power this morning. Although most of the electric generating plants that went down are expected to be operating today, it may be several days before some of them are returned to service."

Here are some recommendations to help businesses and residential customers reduce your electric use:

- If you're away from home for the day or your business is closed, turn off your central air conditioner or raise its setting above 78 degrees;
- When home or at your business, raise the temperature on your central air conditioner to 78 degrees or the highest setting comfortable;
- Close off unoccupied areas and shut air-conditioning vents;

(more)

Energy Conservation
Page Two

- Close blinds, shades and drapes to keep your home or office more comfortable at higher temperature settings and help your fans and air conditioners work more efficiently;
- Turn off all unnecessary lights, equipment and appliances;
- Prepare meals that require little or no cooking;
- Delay running your dishwasher, clothes washer and dryer until late evening;
- Set fax machines and printers for sleep mode when not in use. Network one printer for several users;
- Make sure the power management feature is enabled on computers and set to the shortest acceptable time for your operation. Use laptops instead of personal computers.

In most cases, regular telephone service will be available even though electric power is not.

The MPSC is an agency within the Department of Consumer and Industry Services.

###

GEORGE VOINOVICH
OHIO

United States Senate
WASHINGTON, D. C. 20510

September 2, 2003

The Honorable Pete Domenici, Chairman
Committee on Energy and Natural Resources
364 Dirksen Senate Office Building
United States Senate
Washington, DC 20510

The Honorable Billy Tauzin, Chairman
Committee on Energy and Commerce
2125 Rayburn House Office Building
United States House of Representatives
Washington, DC 20515

Dear Chairman Domenici & Chairman Tauzin:

As you are preparing to chair the House Senate Conference on H.R. 6, a comprehensive Energy Bill, I am writing to express my concerns about America's electricity system and to request your support for legislation that will help strengthen that system.

The recent blackout that affected parts of Ohio, as well as parts of Pennsylvania, New York, Michigan and Ontario, Canada, was only the most recent illustration of the vulnerability of our Nation's electricity transmission system – a system that is in urgent need of modernization. Over the last 40 years, the system has become congested and strained because growth in electricity demand has not been matched by corresponding investment in new generation and transmission facilities. Further, our existing transmission infrastructure was not designed to meet present demand and daily transmission constraints increase the risk of blackouts.

Ohio has long served as the center of our Nation's manufacturing base, and currently has over 860,000 people in manufacturing jobs. Manufacturers in Ohio – and Nationwide – depend on adequate supplies of affordable and reliable electricity in order to remain competitive in the world market.

In order to ensure that our manufacturers – as well as our health-care providers, educators, farmers and those working in the service, retail and technology sectors – have the energy they need to do their jobs, we must have an electricity system that includes both adequate generation and robust transmission. I respectfully urge the Conference Committee to consider factors that will encourage the construction of transmission and generation in places where it will be most beneficial to consumers.

In order to encourage investment in the transmission grid, and to ensure the reliability of the grid, a comprehensive Energy Bill must include provisions that will:

> **Ensure that the transmission system is reliable** – Provisions to establish reliability standards to prevent instability and cascading failures of the system are included in both the House-passed and Senate-passed versions of H.R. 6. I encourage the conference to include such provisions in the Conference Report.

Protect regional deference – It is important that any language dealing with FERC's Standard Market Design rulemaking contains an appropriate clarification that such language is not intended to interfere with regional efforts at market development and reliability improvements underway by established Regional Transmission Organizations. It is also important that any provisions included in the Energy Bill will not interfere with regional efforts to address issues associated with such market development and reliability improvement efforts.

Facilitate siting of new transmission corridors – Last year I sponsored legislation (S. 1590) to amend the National Environmental Policy Act of 1969 and streamline the siting process for transmission corridors. I encourage the conference to adopt this language, which I have attached, as part of the Energy Bill.

Further, in order to ensure, that we have an adequate supply of electricity, the Energy Bill must include provisions that will:

Increase domestic production of natural gas – Both the House-passed and Senate-passed version of H.R. 6 include provisions to increase domestic production of natural gas and to ensure that we have a healthy, vital fuel mix for electric generation. These are important provisions that should be included in the Conference Report.

Promote alternatives to natural gas – Both the House-passed and Senate-passed version of H.R. 6 include provisions to encourage alternatives to natural gas for electricity generation – such as nuclear power, hydropower, renewable energy and clean coal – which are vital in order to relieve the pressure on our natural gas supply. Continued and expanded use of these fuels to generate electricity is vital to having a healthy generation mix.

Finally, efforts to regulate emissions of carbon will force our utilities to fuel switch to natural gas, will significantly raise energy prices, will cause thousands of jobs to be lost and are directly contrary to the policies that we are trying advance in passing a comprehensive Energy Bill. The conferees should not include any language on climate change in the Conference Report.

Encouraging the development of robust and reliable transmission, as well as adequate supplies of electricity, will help to ensure that we do not face blackouts such as the one that recently hit our Nation. Thank you for your consideration of my concerns.

Sincerely,

George V. Voinovich

George V. Voinovich
United States Senator

PAT WOOD, III, RESPONSES TO QUESTIONS FROM SENATOR FRANK R. LAUTENBERG

Question 1: Mr. Wood, the newspapers have reported on a deal the Administration made to delay FERC's Standard Market Design Rule, and prevent the Commission from requiring mandatory participation in RTOs until 2007.

If electricity deregulation and RTO participation are dramatically slowed, what effect do you think that will have on the risks of future blackouts?

Answer: At this time, we are still working with the United States - Canada Joint Task Force to determine what caused the August 14, 2003 blackout that cascaded through eight states and parts of Canada.

As to the risk of future blackouts, however, one of the ways in which the Commission is fostering a more reliable electricity system is by promoting regional coordination and planning of the interstate grid through regional transmission organizations (RTOs) and independent system operators (ISOs). (The major distinction between the two entities is that an ISO can be geographically smaller than an RTO). They can also bolster the reliability of the grid through unified operation of the transmission system across a broad region. Participation in RTOs and ISOs provide these benefits to both regulated and competitive retail markets.

In Order No. 2000, the Commission recognized that regional organizations have unique advantages to assist in regional planning for new transmission infrastructure. The Commission required that RTOs have a regional planning process to identify and arrange for necessary transmission additions and upgrades. With respect to operating the interstate transmission grid, in Order No. 2000, the Commission identified the benefits of large, independent regional entities to operate the grid, and strongly encouraged, but did not require, utilities to join together to form such entities. The Commission noted that such entities would improve reliability because they have a broader, more regional perspective on electrical operations than many separate utilities. In addition, some 130 control area operators currently manage the operation of the transmission grid, whereas a smaller number of regional organizations could manage the grid more effectively. Further, unlike utilities that own both generation and transmission, RTOs are independent of market participants and, therefore, lack a financial incentive to use the transmission grid to benefit any one market participant.

Question 2: Mr. Wood, yesterday I was visited by several employees of FirstEnergy. They reported to me that FirstEnergy is using power transmission lines at well-over capacity and has failed to replace sections of old, unreliable infrastructure. Can FERC play a role to address this sort of dangerous and irresponsible behavior on the part of a utility?

Answer: The Commission has no explicit authority to inspect or require the replacement of old, unreliable infrastructure. Historically, state regulators carried out this function. However, the Commission has offered an enhanced return on equity for new transmission infrastructure in rates under its jurisdiction. More generally, there is no direct federal authority or responsibility for the reliability of the transmission grid. The Federal Power Act contains only limited authorities on reliability. Congress is now considering, in conference, energy legislation that provides for mandatory electric reliability rules, subject to Commission oversight. The mandatory electric reliability standards authorized in the Senate version of H.R. 6 would allow the Commission to oversee short-term reliability by approving requirements for the operation of the bulk-power system. My understanding is that these requirements could address, and limit, intentional overloading of transmission lines.

I believe that mandatory reliability standards are critical to our Nation's security. If Congress wishes to establish an even stronger federal role in ensuring long-term reliability of the bulk-power system, H.R. 6 could be revised to authorize an electric reliability organization, subject to Commission oversight, to order the construction of additional transmission capacity.